10.1 SUMMARY DESCRIPTION

The components of the steam and power conversion system are designed to produce electrical power from the steam coming from the reactor, condense the steam into water, and return the condensate to the reactor as heated feedwater, with a major portion of the gaseous, dissolved, and particulate impurities removed.

The Power conversion system consists of the following components:

1) Turbine Generator with Auxiliaries
2) Main Condenser
3) Condensate Pumps
4) Air Ejector with Water Condenser
5) Gland Steam Condenser
6) Condensate Filters
7) Condensate Demineralizers
8) Five Stages of Feedwater Heaters
9) Reactor Feed Pumps with Turbine Drives and Auxiliaries
10) Interconnecting Piping and Valves
11) Drain Coolers

Steam generated in the reactor is supplied to the high pressure turbine through the main stop and control valves. The steam then passes through the high pressure (HP) turbine and exhausts through cross around lines to two moisture separators which remove moisture from the steam. The dried steam leaves the moisture separators and enters the low pressure (LP) turbines, which share a common shaft with the HP turbine, through combined intercept valves. After passing through the low pressure turbines the steam exhausts to the main condensers where it is condensed by the circulating water system (Subsection 10.4.5), deaerated, and collected in the hotwell of the condenser. The condensate pumps remove the condensate from the hotwell and pump it through the air ejector intercondenser, the gland steam condenser, the condensate filters, the condensate demineralizers, the drain coolers and the five stages of feedwater heaters to the suction of the reactor feed pumps which pump the condensate back into the reactor vessel.

Steam is extracted from the HP and LP turbines and used to heat the condensate as it passes through the various feedwater heaters. The extraction steam is condensed in each heater and the condensed steam drained to the next lowest pressure heater. The total cascaded heater drains are collected in the drain cooler from which they drain back to the condenser. The moisture removed from the steam by the moisture separators is drained to Heater No. 4 where it mixes with the condensed extraction steam and is eventually drained back to the condenser.

Should the water level in any heater or moisture separator become too high, the drains will be dumped directly to the condenser to prevent water damage to the turbine.

If the reactor produces more steam than the turbine can use, the excess, at least 22 percent of reactor rated steam flow, is dumped to the condenser through the bypass valves (See Subsection 10.4.4).

The steam and power conversion systems are sized for the turbine design conditions.

Biological shielding is provided around the main turbine, moisture separators, feedwater heaters, condensers and reactor feed pump turbines to protect operating personnel from exposure to high radiation levels. Section 12.3 provides additional discussion on radiation protection.

Figures 10.1-1a, 10.1-1b, 10.1-2a and 10.1-2b show the guaranteed and VWO turbine heat balances for Units 1 and 2, respectively. The Guaranteed Flow turbine heat balances shown in Figures 10.1-1a and 10.1-1b have a slightly different inlet enthalpy than the exit enthalpy shown for the reactor heat balances in Figures 1.2-49, 1.2-49-1, 1.2-49-2 and 1.2-49-3. The design reactor heat balance is based on actual, measured steam moisture values, with a compensation for pressure drop made to obtain conditions at the MSIV exit. The turbine heat balances shown in Figures 10.1-1a and 10.1-1b are design calculations for the turbine, and input steam conditions are assumed to have a slightly greater moisture fraction.

Typical design parameters are summarized in Table 10.1-1 and Table 10.1-1A.

Instrumentation is commercial quality, designed to meet the process requirements and the turbine generator supplier’s requirements. These instruments are described further in Sections 10.2 through 10.4. The turbine instrumentation for control valve fast closure and stop valve closure which initiates scram in the RPS is discussed in Subsection 7.2.2.1.3.

TABLE 10.1-1

UNIT 1 - SUMMARY OF TYPICAL DESIGN AND PERFORMANCE CHARACTERISTICS OF POWER CONVERSION SYSTEM

1.Steam Conditions at Turbine Throttle Valve	
a. Flow (10^6 lb/hr)	16.51
b. Pressure (psia)	976
c. Temperature (°F)	541.7
d. Enthalphy (Btu/lb)	1190.3
e Moisture Content (%)	0.53
2. Feedwater Conditions	
a. Flow (10^6 lb/hr)	16.52
b. Temperature (°F)	399.8
3. Condenser	
a. Air Inleakage (cfm)	75
b. Hotwell Detention Capacity (min)	2
4. Main Steam Bypass Capacity (%VWO)	≥21

TABLE 10.1-1a

UNIT 2 - SUMMARY OF TYPICAL DESIGN AND PERFORMANCE CHARACTERISTICS OF POWER CONVERSION SYSTEM

1. Steam Conditions at Turbine Throttle Valve	
a. Flow (10^6 lb/hr)	16.50
b. Pressure (psia)	976
c. Temperature (°F)	541.7
d. Enthalphy (Btu/lb)	1190.3
e. Moisture Content (%)	0.53
2. Feedwater Conditions	
a. Flow (10^6 lb/hr)	16.51
b. Temperature (°F)	399.4
3. Condenser	
a. Air Inleakage (cfm)	75
b. Hotwell Detention Capacity (min)	2
4. Main Steam Bypass Capacity (% of reactor rated flow)	≥21

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SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 AND 2
FINAL SAFETY ANALYSIS REPORT

FSAR FIGURE 10.1-1

PP&L DRAWING

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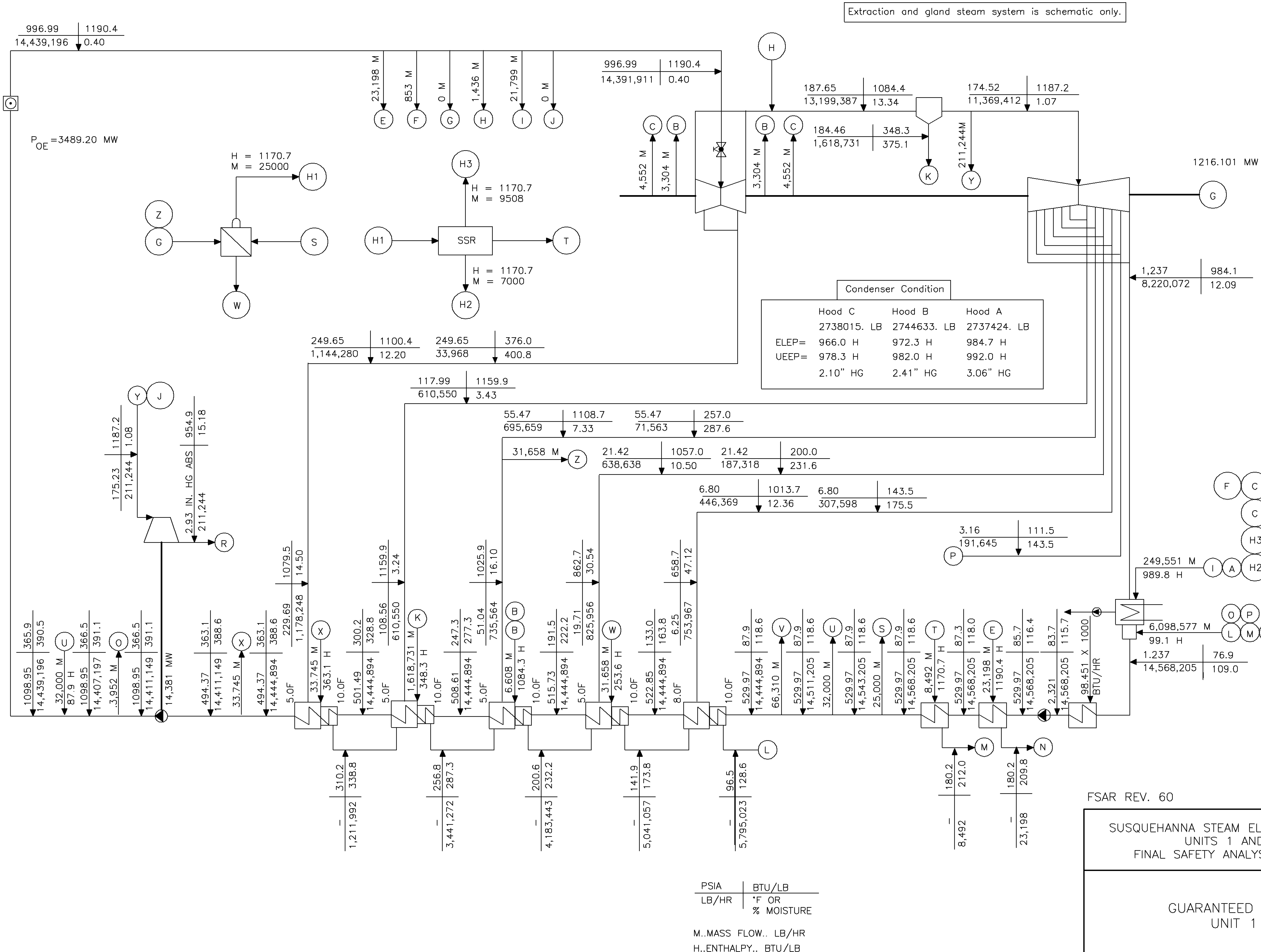
SUSQUEHANNA STEAM ELECTRIC STATION UNITS 1 AND 2 FINAL SAFETY ANALYSIS REPORT
FSAR FIGURE 10.1-2

PP&L DRAWING



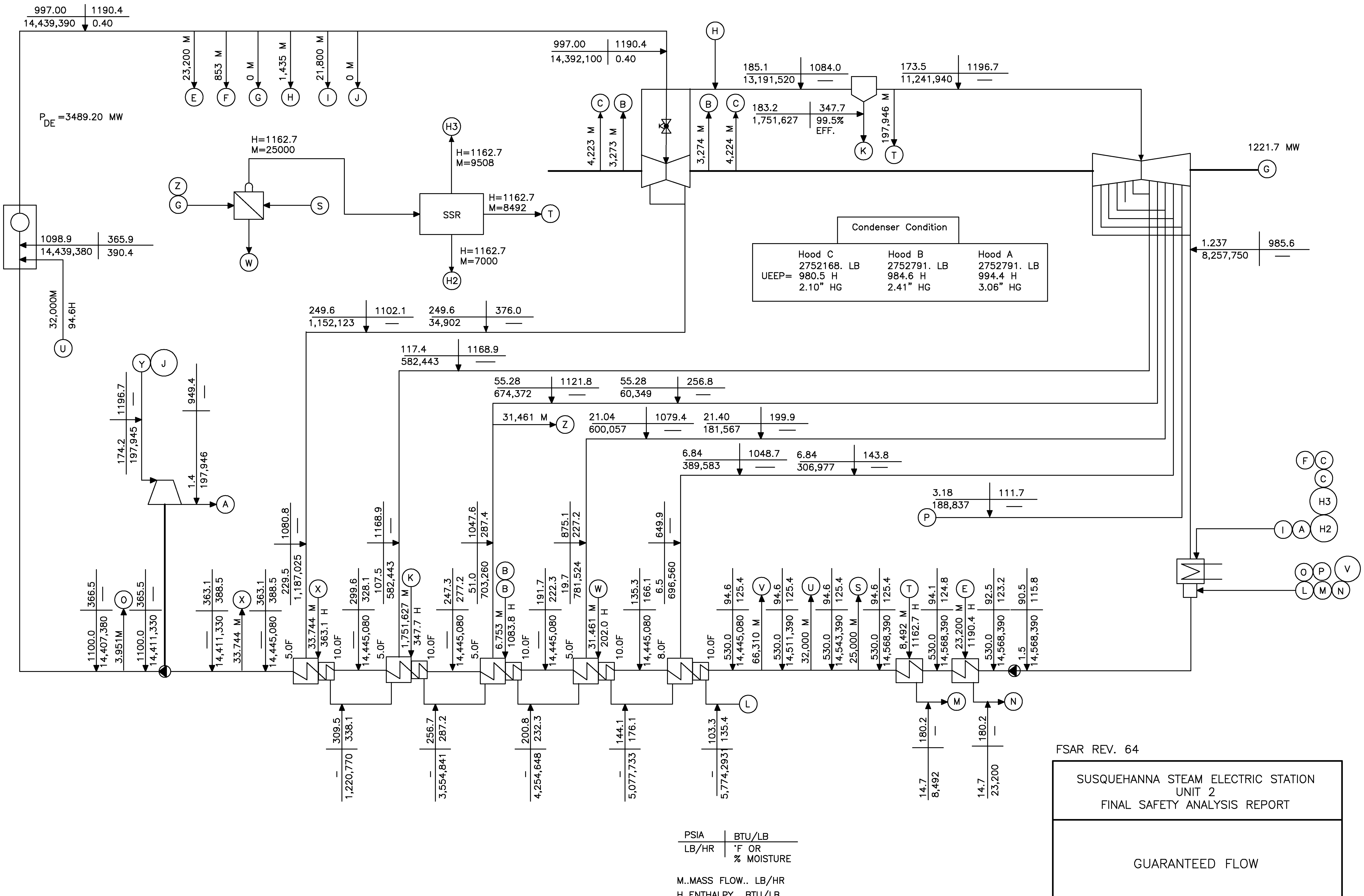
FSAR REV. 60

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 AND 2
FINAL SAFETY ANALYSIS REPORT

GUARANTEED FLOW
UNIT 1

FIGURE 10.1–1A, Rev. 52

Auto-Cad FSAR_10_1_1A.DWG



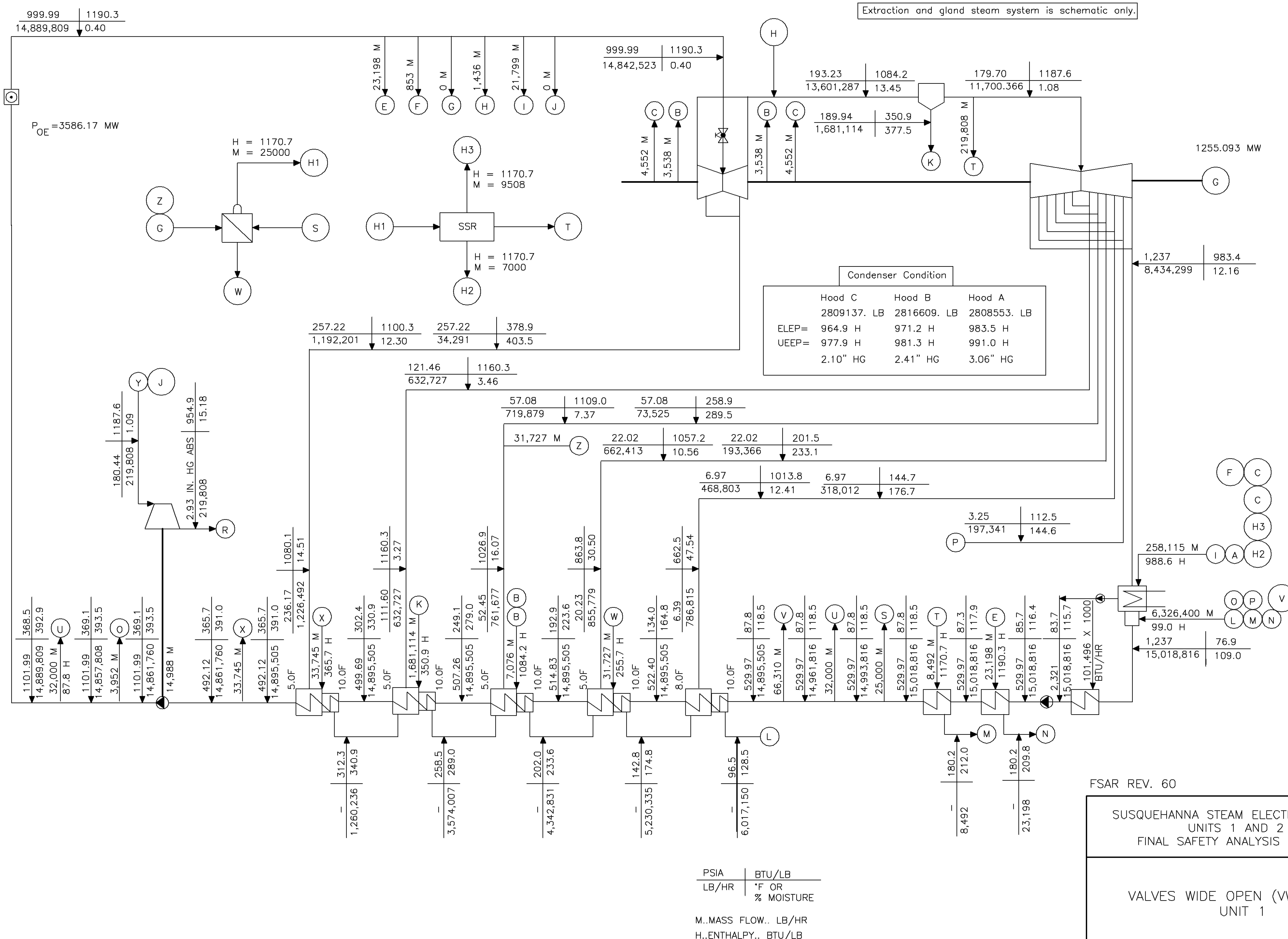
FSAR REV. 64

SUSQUEHANNA STEAM ELECTRIC STATION
UNIT 2
FINAL SAFETY ANALYSIS REPORT

GUARANTEED FLOW

FIGURE 10.1–1B, Rev. 52

Auto-Cad ; FSAR_10_1_1B.DWG



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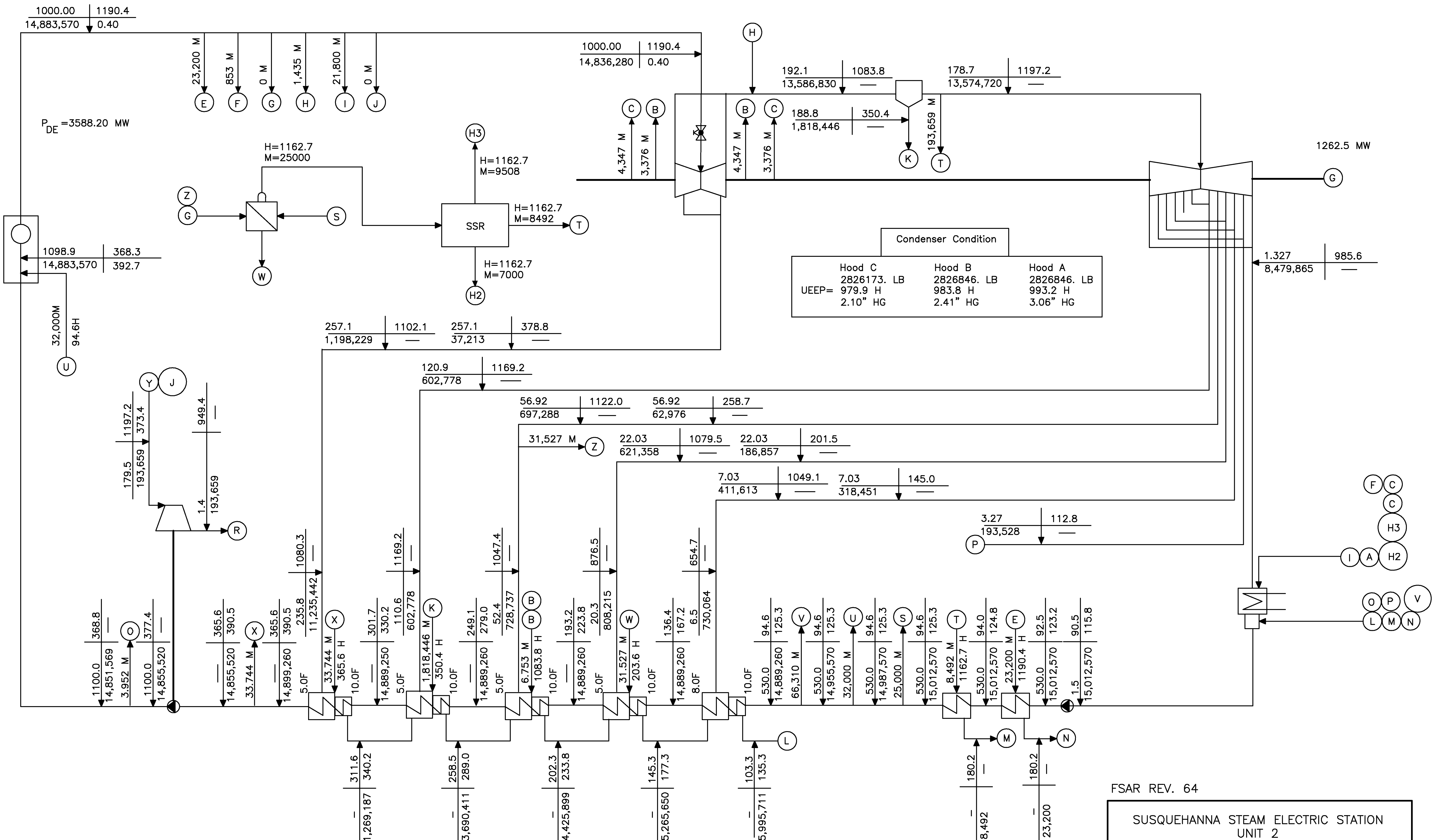
SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 AND 2
FINAL SAFETY ANALYSIS REPORT

VALVES WIDE OPEN (VWO) FLOW
UNIT 1

FIGURE 10.1-2A, Rev. 52

Auto-Cad FSAR_10_1_2A.DWG



PSIA	BTU/LB258.8
LB/HR	°F OR % MOISTURE

M..MASS FLOW.. LB/HR
H..ENTHALPY.. BTU/LB

FSAR REV. 64

SUSQUEHANNA STEAM ELECTRIC STATION
UNIT 2
FINAL SAFETY ANALYSIS REPORT

VALVES WIDE OPEN (VWO) FLOW

FIGURE 10.1-2B, Rev. 51

Auto-Cad ; FSAR_10_1_2B.DWG

10.2 TURBINE-GENERATOR

10.2.1 DESIGN BASES

For both Unit 1 and Unit 2, the turbine is a 1,800 rpm, tandem compound, six-flow, non-reheat steam turbine with 46 in. last-stage blades. The capability of the turbine for Unit 1 is 1,345,812 kW and for Unit 2 is 1,350,108 kW when operating with initial steam conditions of 976.1 psia, and 1190.3 Btu/lbm, while exhausting to the multipressure condenser at 2.39, 2.77, and 3.59. HgAbs back pressures; with 0 percent makeup and extracting steam for the normal five stage feedwater heating and feed pump turbine drives. The turbines can produce approximately 1,383,809 kW for Unit 1 and 1,388,531 kW for Unit 2 when operating at valves wide open (VWO) and with the corresponding design VWO steam and cycle conditions shown on the heat balances. (Reference 10.2-10, and 10.2-11).

The generator is a 1,354,000 KVA, 1800 rpm, direct connected, 4 pole, 60 Hz, 24,000 V, liquid cooled stator, hydrogen cooled rotor, synchronous rated at 0.935 power factor, 0.57 short circuit ratio at a maximum hydrogen pressure of 75 psig. The output of the turbine and reactor will be limited to maintain approximately 1300 MWe from the generator in order to stay within the generator capability.

The Alterrex excitation system consists of a 60 Hz, 1,800 rpm air cooled Alterrex generator and liquid cooled rectifiers with static thyristor automatic regulation equipment. The exciter is rated for a maximum output of 3210 kW at 530 V.

The turbine generator control is accomplished by an electrohydraulic control (EHC) system capable of controlling speed, load, steam pressure and flow under startup, shutdown, transient and steady state conditions.

The turbine-generator is normally base loaded. The load following capability has been electrically disconnected.

The turbine-generator units, originally GE design, are built in accordance with GE standards and codes for existing GE components and to Siemens standards and codes for new replacement turbine components. The moisture separator vessels and steam seal evaporator vessels are built in accordance with ASME B&PV Code, Section VIII.

The steam generation rate has the ability to follow turbine load demand changes by as much as 35 percent without control rod movement merely by changing the recirculation flow rate through the core. If a load reduction of more than 10 percent occurs, the turbine bypass valves will open momentarily until the recirculation rate is sufficiently reduced. Bypass valves have the ability to bypass at least 22 percent of the reactor rated flow. The turbine control valves are capable of changing turbine steam flow for adequate pressure control performance.

During any event resulting in turbine stop valve closure, turbine inlet steam flow is not reduced faster than permitted by Figure 10.2-1.

During any event resulting in turbine control valve fast closure, turbine inlet steam flow is not reduced faster than permitted by Figure 10.2-2.

10.2.2 DESCRIPTION

10.2.2.1 Turbine

The turbine unit consists of one double flow high pressure turbine and three double exhaust flow low pressure turbines. The unit includes two horizontal moisture separator vessels located on the operating floor, one on each side of the turbine. The moisture separator vessels are of the non-reheat type.

Steam from the reactor enters the power conversion system through four main steamlines. Each of the four main steamlines to the high pressure turbine is connected to a main steam stop valve and a main steam control valve. The four stop valves and four control valves are combined to form a single valve chest. A pressure equalizing line connects the stop valves together just below the valve seats. Six combined intermediate valves (CIV) (each composed of an intercept valve and an intermediate stop valve) are located in the lines between the moisture separator vessels and the low pressure turbines. A five valve bypass valve chest is connected to each of the main steamline between the main steam isolation valves and main steam stop valves to remove excess flow to the condenser.

There is one stage of extraction from the high pressure turbine and four stages of extraction from each low pressure turbine. The extraction steam is used to heat the five stages of feedwater heating.

A portion of the cross-around steam is used to drive the reactor feed pump turbines (RFPTs) during normal operation.

The turbine-generator is provided with an emergency trip system that closes the main stop valves, control valves and combined intermediate valves, thus shutting down the turbine, on the following signals:

1. Turbine approximately 10% above rated speed.
2. Turbine approximately 12% above rated speed.
3. Vacuum decreases to less than 21.7 Hg.
4. Excessive thrust bearing wear.
5. Deleted.
6. Prolonged loss of generator stator coolant.
7. Electrical trip, via master trip solenoids.
8. Loss of hydraulic fluid supply pressure. Loss of emergency trip system fluid pressure automatically closes the turbine valves and then energizes the master trip relay to prevent a false restart at 1100 psig decreasing.
9. Signal from High turbine vibration.
10. Loss of both speed signals above 100 rpm.

11. Loss of both the primary and secondary 24 VDC power supplies.

12. Mechanical trip via manual trip handle of mechanical trip solenoid.

13. High level in a moisture separator drain system.

14. Main shaft lube oil pump low pressure trip above 1300 rpm.

15. Primary and backup unit protection lockout relay trip.

16. High reactor water level trip at 54".

17. Loss of ETS pressure trip at 800 psig decreasing.

18. Power/Load Imbalance >40%.

At reactor power greater than 26 percent, tripping the turbine will automatically cause the reactor to scram.

10.2.2.2 Generator and Exciter

The generator stator is water cooled and the rotor is hydrogen cooled. The generator hydrogen system includes all necessary controls and regulators for hydrogen make-up (See Dwg. M-133, Sh. 1). The hydrogen purity inside the generator is monitored on a continual basis. The pipe from the Generator Hydrogen system is routed below grade to the generator and does not enter any safety related areas. A seal oil system is provided to prevent hydrogen leakage through the generator shaft seals. The Bulk Hydrogen system is located between the cooling towers at grade level. A hydrogen makeup supply is provided outside the turbine building to replace any hydrogen leakage from the generator. To avoid having an explosive hydrogen-air mixture in the generator at any time, either when the generator is being filled with hydrogen prior to being placed into service, or when hydrogen is being removed from the generator prior to opening the generator for inspection or repairs, carbon dioxide is used for purging out the air or hydrogen in the generator casing. The generator is designed to withstand a hydrogen detonation.

Automatic water type fire protection systems are provided to protect the turbine and generator bearings, the area below the generator, the hydrogen seal oil system, the permanent bulk hydrogen storage area and the hydrogen truck unloading area. In addition, portable fire extinguishers and fire hose are provided inside the turbine building.

10.2.2.3 Protective Valves Functions

The primary function of the turbine stop valves is to quickly shut off steam to the turbine under emergency conditions. The stop valve disks are totally unbalanced and cannot open against full pressure drop. An internal bypass valve is provided in one of the four stop valves to permit slow warming of all stop and control valves and to pressurize the stop valve below seat area to allow valve opening.

The function of the turbine control valves is to throttle steam flow to the turbine. The valves are of sufficient size, relative to their cracking pressure, to require that they be partially balanced. A small internal valve is opened first to decrease the pressure in a balance chamber. The valves are opened by individual hydraulic cylinders.

The function of the bypass valves is to pass steam directly from the reactor to the condenser without the steam going through the turbine. The bypass valve chest is connected directly to the steam leads from the reactor. This chest is composed of five valves operated by individual hydraulic cylinders. When the valves are open steam flows from the chest, through the valve seat, out the discharge casing, and through connecting piping to the pressure breakdown assemblies where a series of baffle plates and orifices is used to further reduce the steam pressure before the steam enters the condenser. (See Subsection 10.4.4)

The function of the combined intermediate valves (CIV's) is to protect the turbine against overspeed from stored steam in the cross-around piping, moisture separator vessels, HP turbine, and main steam lines (downstream of control valves), and to throttle and balance steam flow to the LP turbines. Each valve is composed of an intercept valve and an intermediate stop valve incorporated into a single casing. The two valves have separate operating mechanisms and controls. The valves are located as close to the low pressure turbine as possible to limit the amount of uncontrolled steam available as an overspeed source.

During normal plant operation the intercept valves will be open. The intercept valves are capable of opening against maximum cross-around pressure and of controlling turbine speed during blowdown following a load rejection. The intermediate stop valves also remain open for normal operation and trip closed by actuation of the emergency governor or operation of the master trip. They provide backup protection if the intercept valves or the normal control devices fail.

10.2.2.4 Extraction System Check Valves

The energy contained in the extraction and feedwater heater system can be of sufficient magnitude to cause overspeed of the turbine-generator following an electrical load rejection or turbine trip. To prevent this the energy must be contained in the piping and feedwater heaters. This is done by installing positive closing bleeder trip valves (PCBTV) or antiflash baffles in the heaters. GE steam turbine design rules and code requirements specify that the turbine controls will be capable of preventing the turbine speed from rising above a certain maximum value after a full load rejection or trip. The PCBTV valves and antiflash baffles limit the amount of energy flashing back into the turbine so that the turbine speed increase is held below the maximum value. Antiflash baffles are used in feedwater heaters 1 and 2 extraction steamlines since the distance to the turbine is short and internal energy is low. PCBTVs are installed in the extraction lines, to feedwater heaters 3, 4, and 5.

10.2.2.5 Control System

The turbine generator control system is a GE Mark I electrohydraulic control (EHC) system. The speed control unit produces the speed/acceleration error signal that is determined by comparing the desired speed from the reference speed circuit, with the actual speed of the turbine for steady state conditions. For step changes in speed, an acceleration reference circuit takes over to either accelerate or decelerate the turbine at a selected rate to the new speed. There is no limit to the deceleration. The speed/ acceleration error signal is combined with the load requirements on the load control unit to provide the flow signal to the control valves. Because of the importance of overspeed protection the speed control signal has two independent redundant channels. Two independent pulse signals are obtained from magnetic pick-ups located over a gear-toothed wheel on the turbine shaft. Loss of both speed signals will trip the turbine.

10.2.2.6 Overspeed Protection

To protect the turbine generator against overspeed two trip devices are provided either of which when initiated will close the main stop valves, control valves, and combined intercept valves thus shutting down the turbine.

These two trip devices are as follows:

1. A mechanical overspeed trip which is initiated if the turbine speed reaches approximately 10% above rated speed, and

2. An electrical overspeed trip which serves as a backup to the mechanical trip and is initiated at approximately 12% above rated speed.

The mechanical overspeed trip device is an unbalanced ring mounted on the turbine shaft and held concentric with it by a spring (See Figure 10.2-3). When the turbine speed reaches the trip speed (10% above rated) the centrifugal force acting on the ring overcomes the tension of the spring and the ring snaps to an eccentric position. In doing this it strikes the trip finger which operates the mechanical trip valve, MTV. This is a three way valve that feeds hydraulic fluid (1600 psi) to the lockout valve, and when tripped blocks the hydraulic fluid supply system and removes the emergency trip system pressure which causes the main stop valves, control valves and combined intercept valves to close. Failure of the hydraulic portion of this trip will result in a stop valve closure.

The electrical overspeed trip receives its signal from a 112% speed trip relay (VCS840) that is operated by a speed signal sensed by a magnetic pickup from a toothed wheel on the turbine shaft and fed to a power amplifier and megacycles circuit whose output is a dc voltage proportional to speed (See Dwg. M2H-54, Sh. 1).

The signal from the speed trip relay energizes the master trip relay XKT1000 (Dwg. M2J-101, Sh. 5) which then energizes the mechanical trip solenoid MTS and deenergizes the master trip solenoid valves MTSV-A & MTSV-B.

Either one of these actions will trip the turbine, that is close stop, control and combined intercept valves.

When the overspeed trip system is under test, the lockout valve, LV, is actuated which bypasses the mechanical trip valve. However, under this condition, system protection is provided by the backup overspeed trip acting on the master trip solenoid valve, MTSV, by deenergizing MTSV-A & MTSV-B.

An additional feature of the protective system which will minimize the likelihood of an overspeed condition is the power/load unbalance circuitry (Figure 10.2-6). Generator load is sensed by means of three current transformers and is compared with the turbine power input which is sensed by the turbine intermediate pressure sensor. If the difference between the steam power input and the generator output rises to at least 40% in 35 msec, auxiliary relays will be actuated which will energize the control valves fast closing solenoids, remove the load reference at the load control unit and automatically drive the load reference motor to zero setpoint.

Table 10.2-1 summarizes the overall turbine overspeed protection assurance that stable operation following a turbine trip can be obtained from the requirement that both the stop valves and the combined intercept valves close in a turbine trip thereby accomplishing two things: a) Preventing steam from the main steam line from entering the turbine and b) preventing the expansion of steam already in the high-pressure stage and in the moisture separator. An additional provision is also made to isolate the major steam extraction lines from the turbine.

There are four steam lines at the high pressure stage, each line is provided with one stop valve and one control valve in series. Steam from the high pressure turbine(s) stages flows to the moisture separators and then to the three low pressure turbine stages. Each of the six low pressure lines has a combined intercept valve which is actually made up of a stop valve in series with a control valve in one housing. All of the above valves close on turbine trip. Assuming a single failure to any one of the above system of 20 valves in case of a turbine overspeed trip signal, the turbine will be successfully tripped. Furthermore, each of the major steam extraction lines, with the exception of the #1 and #2 heaters, have an isolation valve and a bleeder trip valve which are independently closed in case of a turbine trip.

10.2.2.7 Turbine Shell Diaphragms

For overpressure protection of the turbine exhaust hoods and the condenser shells, two diaphragms are provided in each low pressure turbine exhaust hood, which rupture at approximately 5 psig. An exhaust hood spray system is provided to spray condensate into the hoods for overtemperature protection.

10.2.2.8 Turbine-Generator Load Following Capability

The load following capability of the turbine-generator system has been electrically disconnected.

10.2.3 TURBINE DISK INTEGRITY

10.2.3.1 Material Selection

Turbine disk and rotors for turbines operating with light water reactors are forged from vacuum degassed Ni-Cr-Mo-V alloy steel by processes which minimize flaw occurrence and provide adequate fracture toughness. Tramp elements are controlled to the lowest practical concentrations consistent with good scrap selection and melting practices, and consistent with obtaining adequate initial and long life fracture toughness for the environment in which the parts operate. The turbine disk and rotor materials have the lowest fracture appearance transition temperatures (FATT) and highest Charpy V-notch energies obtainable, on a consistent basis from water quenched Ni-Cr-Mo-V material at the sizes and strength levels used. Since actual levels of FATT and Charpy V-notch energy vary depending upon the size of the part and the location within the part, etc., these variations are taken into account in accepting specific forgings for use in turbines for nuclear application. Charpy tests essentially in accordance with Specification ASTM A-370 are included.

10.2.3.2 Fracture Toughness

Suitable material toughness is obtained through the use of materials described in Subsection 10.2.3.1 to produce a balance of adequate material strength and toughness to ensure safety while simultaneously providing high reliability, availability, efficiency, etc., during operation. Bore stress calculations include components due to centrifugal loads, interference fit, and thermal gradients where applicable.

For Siemens turbines, the value of material fracture toughness (K_{IC}) used in the calculations is conservatively based on material specifications for the disks, as correlated from minimum Charpy impact strength. The maximum specified FATT for the Siemens disks is -80°C, which is low enough to ensure that the ambient temperature Charpy impact energies and K_{IC} are in the upper shelf range. If an increase of 50°C in FATT is conservatively assumed for the disk interior, the material toughness will still be in the upper shelf region at ambient temperature. The material used is a Ni-Cr-Mo-V steel forging, which has excellent hardenability. Additional information is provided in the turbine missile report (reference 10.2-9).

Turbine operating procedures are employed to preclude brittle fracture at startup by ensuring that the metal temperature of disks and rotors is adequately above the FATT.

10.2.3.3 High-Temperature Properties

The operating temperatures of the high pressure rotor in turbines operating with light water reactors are below the creep rupture range. Therefore, creep rupture is not considered to be a significant factor in assuring rotor integrity over the lifetime of the turbine. Basic data is obtained from laboratory creep rupture tests.

10.2.3.4 Turbine Design

The Siemens turbine assembly is designed to withstand normal conditions and anticipated transients including those resulting in turbine trip without loss of structural integrity. The LP rotor design utilizes a shrunk-on construction where each disk is shrunk on the LP rotor shaft via interference fit. The first disk is retained by a key on the downstream or exit side. The other two disks are not keyed; the shrink fit is more than sufficient to retain the disks to over 120% of rated speed. The design of the turbine assembly meets the following criteria:

a) The maximum tangential stress in disks and rotors resulting from centrifugal forces, interference fit (shrunk on wheel LP's only), and thermal gradients does not exceed 0.50 of the yield strength of the material at 120% of rated speed.

b) Turbine shaft bearings are designed to retain their structural integrity under normal operating loads and anticipated transients, including those leading to turbine trips.

c) The multitude of natural critical frequencies of the turbine shaft assemblies existing between zero speed and 20% overspeed are controlled in the design and operation so as to cause no distress to the unit during operation.

10.2.3.5 Pre-service Inspection

The pre-service inspection program is as follows:

a) Disk and rotor forgings are rough machined with minimum stock allowance prior to heat treatment.

b) Each rotor and disk forging is subjected to a 100% volumetric (ultrasonic) examination. Each finish-machined rotor and wheel is subjected to a surface magnetic particle and visual examination. Results of the above examination are evaluated by use of Siemens acceptance criteria. These criteria are within those specified for Class 1 components in the ASME Boiler and Pressure Vessel Code, Sections III and V and include the requirement that subsurface sonic indications are either removed or evaluated to assure that they will not grow to a size which will compromise the integrity of the unit during the service life of the unit.

c) All finish-machined surfaces are subjected to a magnetic particle examination. No magnetic particle flaw indications are permissible in bores, holes, keyways, and other highly stressed regions.

d) Each fully bladed turbine rotor assembly is spin tested at 125% of rated speed.

10.2.3.6 Inservice Inspection

The in-service inspection program for the main turbine rotor assembly describes the required inspections and frequency maximum values which ensure the main turbine missile damage probabilities described in Section 3.5.1.3.8 and Table 3.5-10, Turbine System Reliability Criteria are maintained. Inspection and exercising of the stop valves, control valves, and combined intermediate valves provide additional assurance of reliable operation of the turbine overspeed protection system.

The low pressure turbine inspections are performed on a frequency to support the main turbine missile damage probabilities described in Section 3.5.1.3.8. The intervals between main turbine inspections will not exceed 10 years of operation with no cracks visible per reference 10.2-9. If the inspection results in found abnormalities, the probability of generating a missile requires re-calculation and the main turbine inspection frequencies will be adjusted as per reference 10.2-9.

The in-service inspection program for the turbine assembly and valves include the following:

a) Disassembly of the turbine is conducted during plant shutdown coinciding with the in-service inspection schedule. Inspection of all parts that are normally inaccessible when the turbine is assembled for operation, such as couplings, coupling bolts, turbine shafts, low pressure turbine blades, low pressure discs, and high pressure rotors is conducted.

   This inspection consists of visual, surface, and volumetric examinations, as indicated below.

   1. A thorough nondestructive (NDE) examination of all HP disk rotors steam inlet and shaft seal areas is conducted. In addition, all accessible rotor surfaces are inspected visually. This inspection is conducted at intervals of about 10 years.

2. The keyway region of each shrunk on disk LP rotor receives an ultrasonic examination. In addition, each disk is inspected visually and by magnetic particle testing on all accessible surfaces.

3. A visual and surface examination of all blades.

4. A 100% visual examination of couplings and coupling bolts.

b) Dismantle at least one main steam stop valve, one main steam control valve, and one combined intermediate valve, at approximately 3-1/3 year intervals during refueling or maintenance shutdowns coinciding with the in-service inspection schedule and conduct a visual and surface examination of valve seats, wheels, and stems. If unacceptable flaws or excessive corrosion are found in a valve, all valves of its type are inspected. Valve bushings are inspected and cleaned, and bore diameters are checked for proper clearance.

c) Main steam stop and control, and combined intermediate valves are exercised by closing each valve and observing, by the valve position, that it moves smoothly to a fully closed position.

The frequency of turbine valve exercising is dependent on the installed rotor configuration due to concerns over potential generation of turbine missiles. Rotor trains which have a lower probability of generating turbine missiles, or those for which the consequence of missile damage is less safety significant, require less frequent valve exercising. The LP rotors supplied by Siemens have shrunk-on disks and only the first disk is keyed.

Valve Exercising Frequency for Shrunk-on Disk Rotors

The Siemens recommended test interval for main stop, control, and combined intermediate valves is not greater than quarterly/quarterly/quarterly.

d) Perform a Channel Functional check of the turbine overspeed protection circuit at least once per refueling cycle.

10.2.4 EVALUATION

The turbine generator and the related steam system have been radiologically evaluated and the results are described in Chapter 12.

10.2.5 REFERENCES

10.2-1 Deleted.

10.2-2 Deleted.

10.2-3 NE-092-001A, "PP&L Licensing Topical Report, Susquehanna Steam Electric Station Licensing Topical Report for Power Uprate with Increased Core Flow."

10.2-4 Power Uprate Engineering Report for Susquehanna Steam Electric Station, Units 1 and 2, "NEDC-32161P, As Revised by PP&L Calculation EC-PUPC-1001, Revision 0, March, 1994.

10.2-5 Deleted.

10.2-6 PLA-3964, "Changes to Turbine Overspeed Protection System," R. G. Byram to C. L. Miller (April 30, 1993).

10.2-7 GE Technical Information Letter (TIL) 969-3 R1, Periodic Turbine Steam Valve Test - Nuclear Steam Turbines, December 27, 1993.

10.2-8 Deleted.

10.2-9 Missile Probability Analysis Methodology for PP&L Susquehanna, Units 1 & 2 with Siemens Retrofit Turbines, Revision 0, September 23, 2005 – Siemens Proprietary (CT-27386).

10.2-10 Siemens letter, SPG-PPL-0746, “SSES PPL Unit 2 Thermal Kit.”

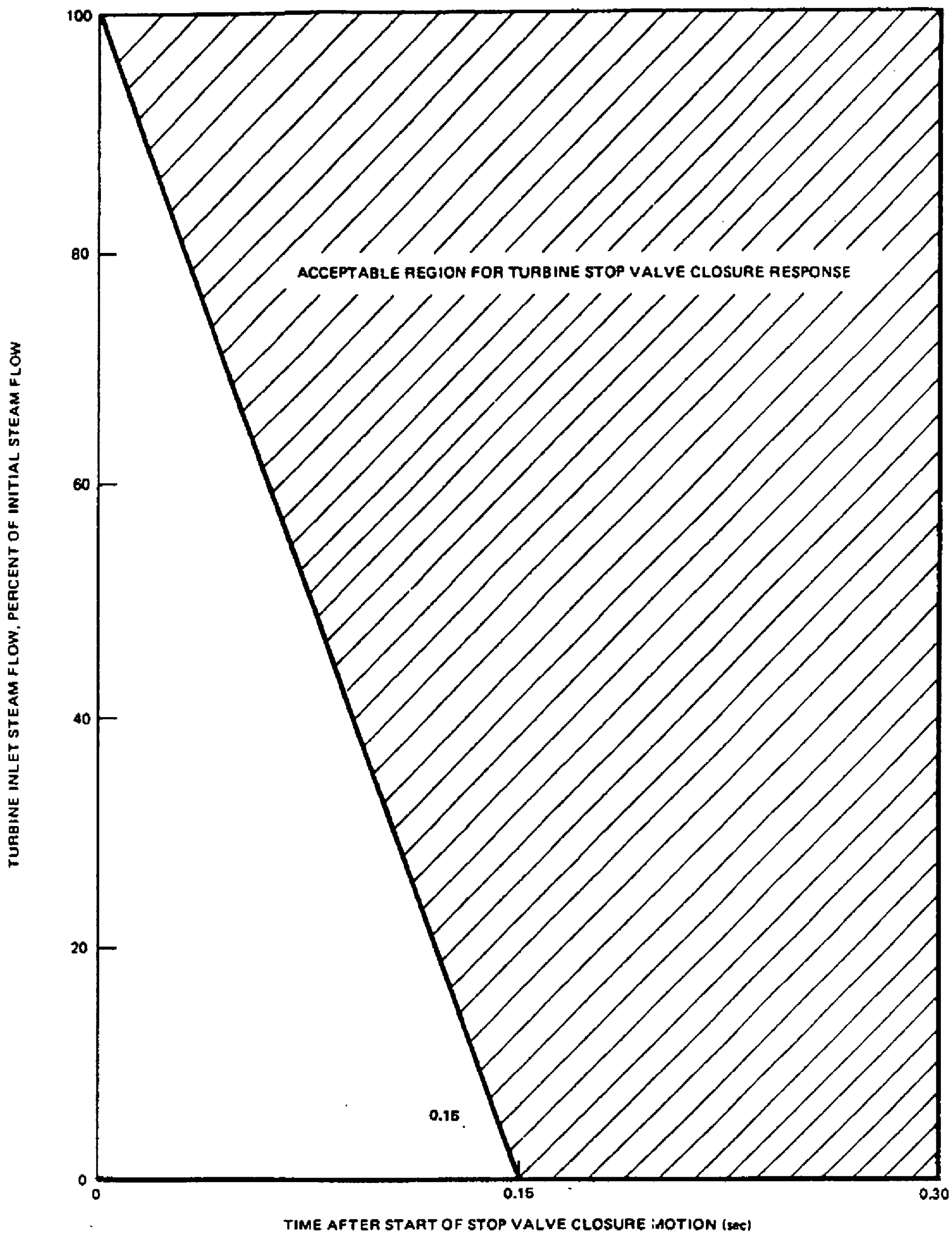
10.2-11 Siemens letter, SPG-PPL-0747, “SSES PPL Unit 1 Thermal Kit ”

10.2-12 Deleted.

TABLE 10.2-1
TURBINE OVERSPEED PROTECTION

DEVICE	DESCRIPTION/FUNCTION	TRIP SETTING	ACTUATING DEVICE INTERMEDIATE	ACTUATING DEVICE FINAL	ACTUATED VALVE	ACTUATED POSITION
Overspeed Trip	Unbalanced ring, concentric with shaft, eccentric on overspeed Close mech. trip Vlv. & remove electro-hyd control oil press	110% of rated speed	Mechanical Linkage	Mechanical Trip VLV	All SV's All CV's All CIV's	Close
Backup Overspeed Trip	Toothed wheel magnetic pick-up speed sensor, electronic signal amplifier Close mech. trip vlv. and master trip sol vlvs.; remove electro. hyd control oil press	112% of rated speed	Master Trip Relay	Mechanical trip solenoid (MTS) & master trip solenoids (MTSV-A&B)	All SV's All CV's All CIV's	Close
Power/ Load Unbalance	Gen current & steam pressure transducers, electronic comparators & control logics Energize CV fast closing solenoids & remove electro-hyd control oil press from the CV's.	40% unbal.			All CV's	Fast Close

NOTE: SV = Stop Valve
CV = Control Valve
CIV = Combined Intercept Valve



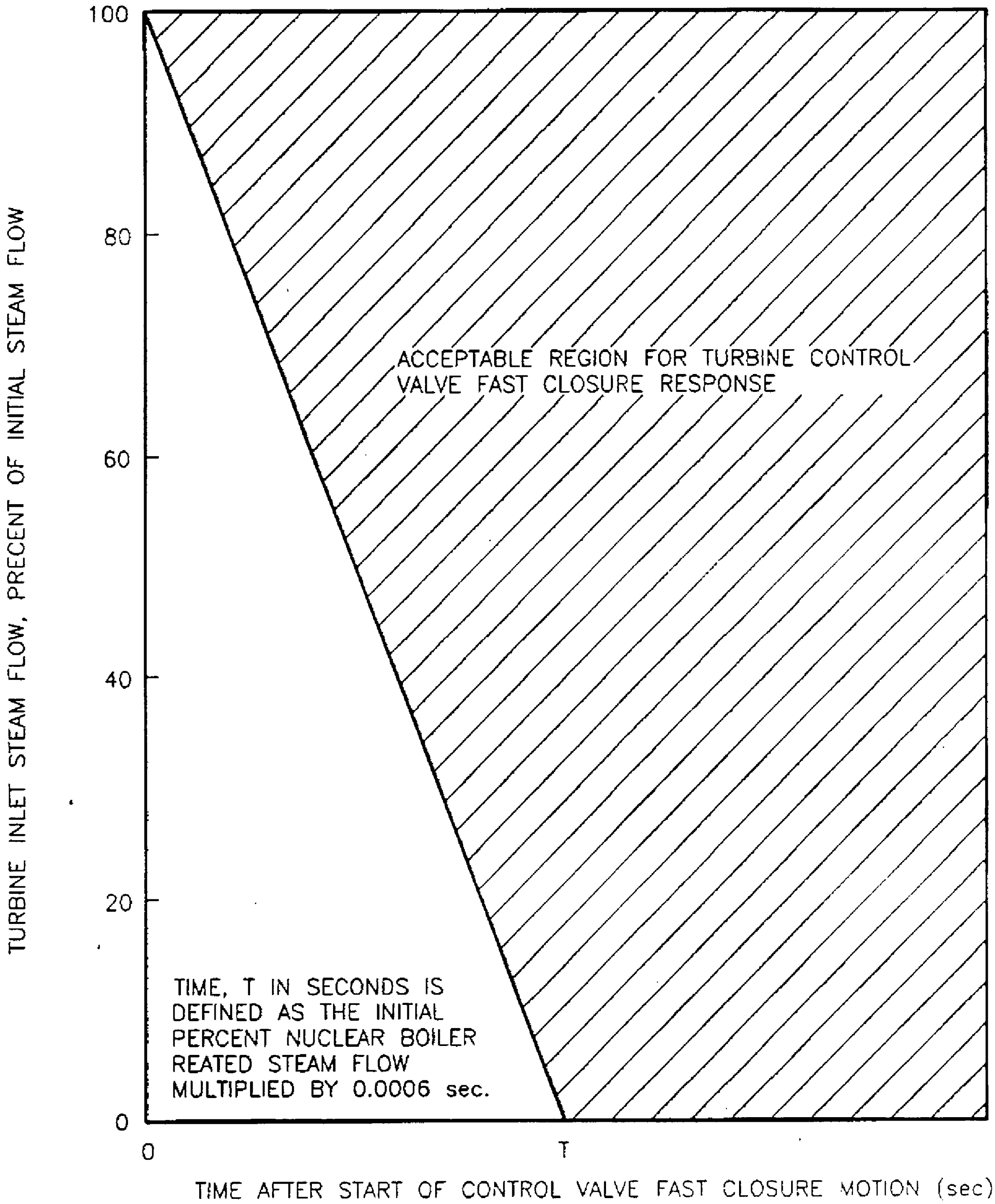
FSAR REV. 48, 12/94

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 AND 2
FINAL SAFETY ANALYSIS REPORT

TURBINE STOP VALVE
CLOSURE CHARACTERISTIC

FSAR FIGURE 10.2-1

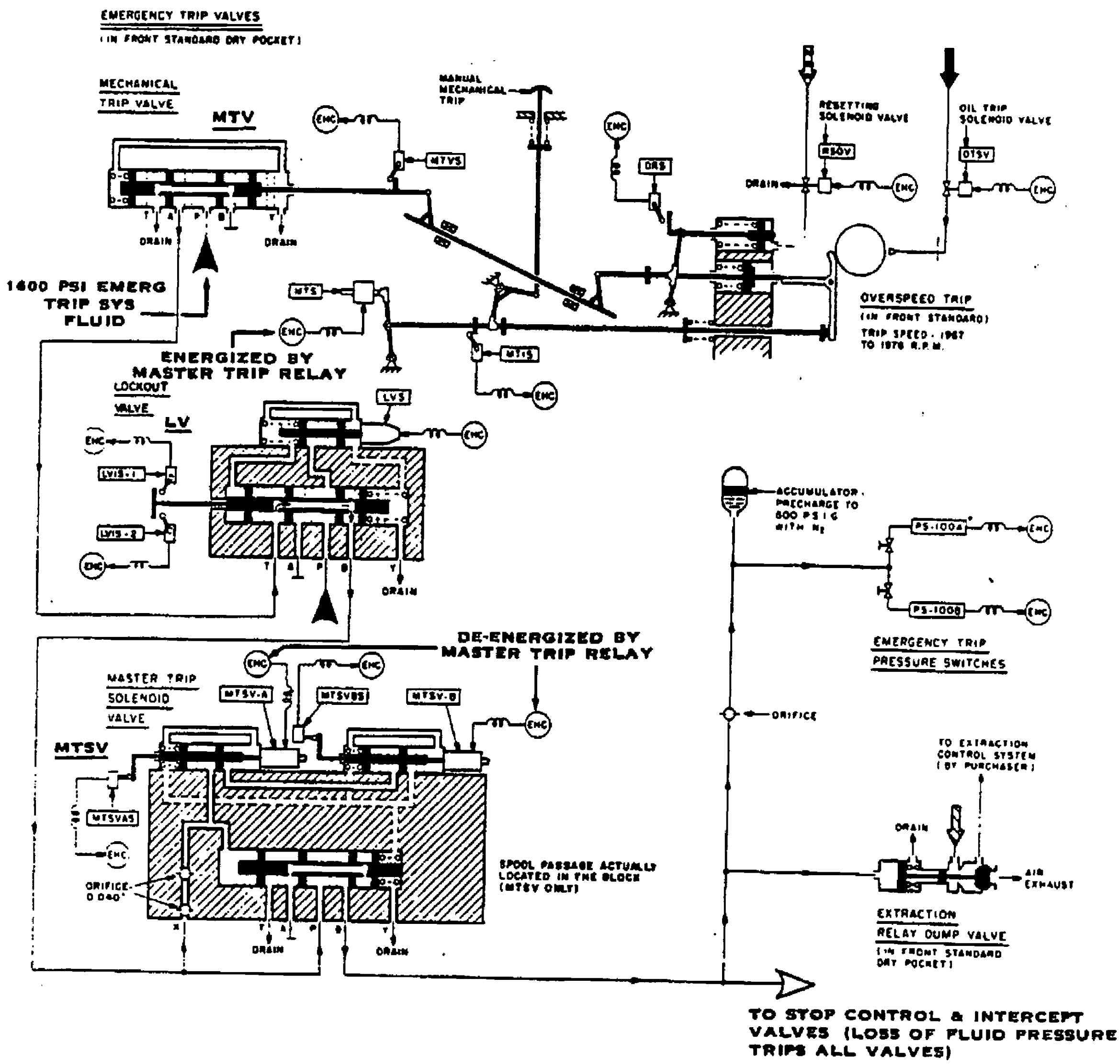
PP&L DRAWING



FSAR REV. 59

SUSQUEHANNA STEAM ELECTRIC STATION UNITS 1 AND 2 FINAL SAFETY ANALYSIS REPORT
TURBINE CONTROL VALVE FAST CLOSURE CHARACTERISTIC
FIGURE 10.2-2, Rev. 49

Auto-Cad FSAR_10_2_2.DWG



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MECHANICAL OVERSPEED TRIP

FSAR FIGURE 10.2-3

PP&L DRAWING

THIS FIGURE HAS BEEN

REPLACED BY DWG.

M2H-54, Sh. 1

FSAR REV. 58

SUSQUEHANNA STEAM ELECTRIC STATION UNITS 1 AND 2 FINAL SAFETY ANALYSIS REPORT
Figure 10.2-4 replaced by dwg. M2H-54, Sh. 1
FSAR FIGURE 10.2-4, Rev. 48

PPL DRAWING FF110680, Sh. 5401

THIS FIGURE HAS BEEN

REPLACED BY DWG.

M2J-101, Sh. 5

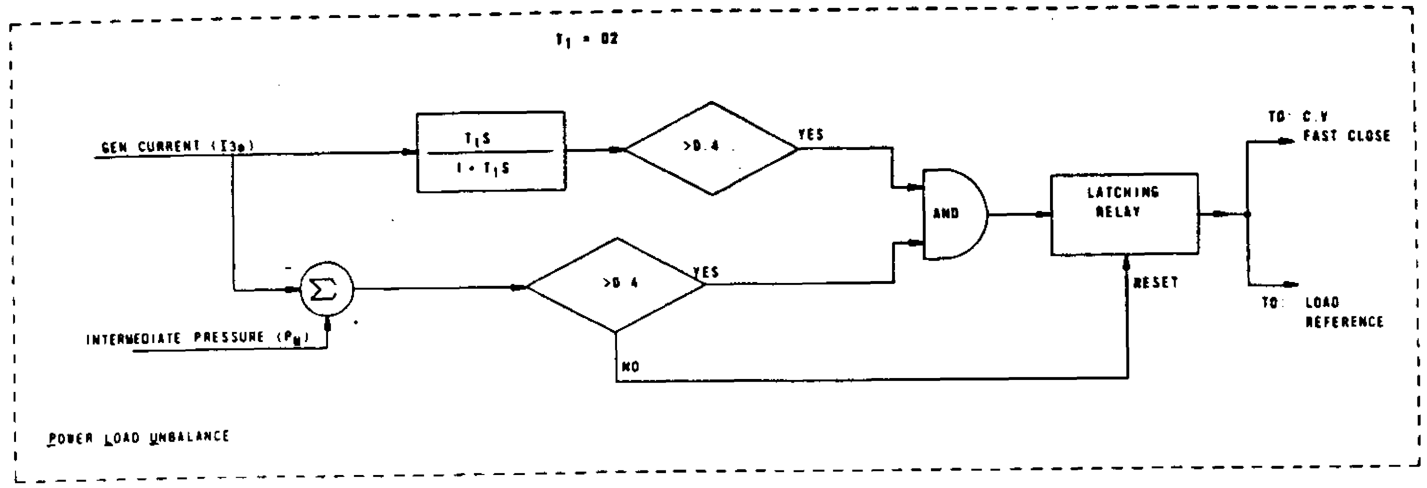
FSAR REV. 58

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 AND 2
FINAL SAFETY ANALYSIS REPORT

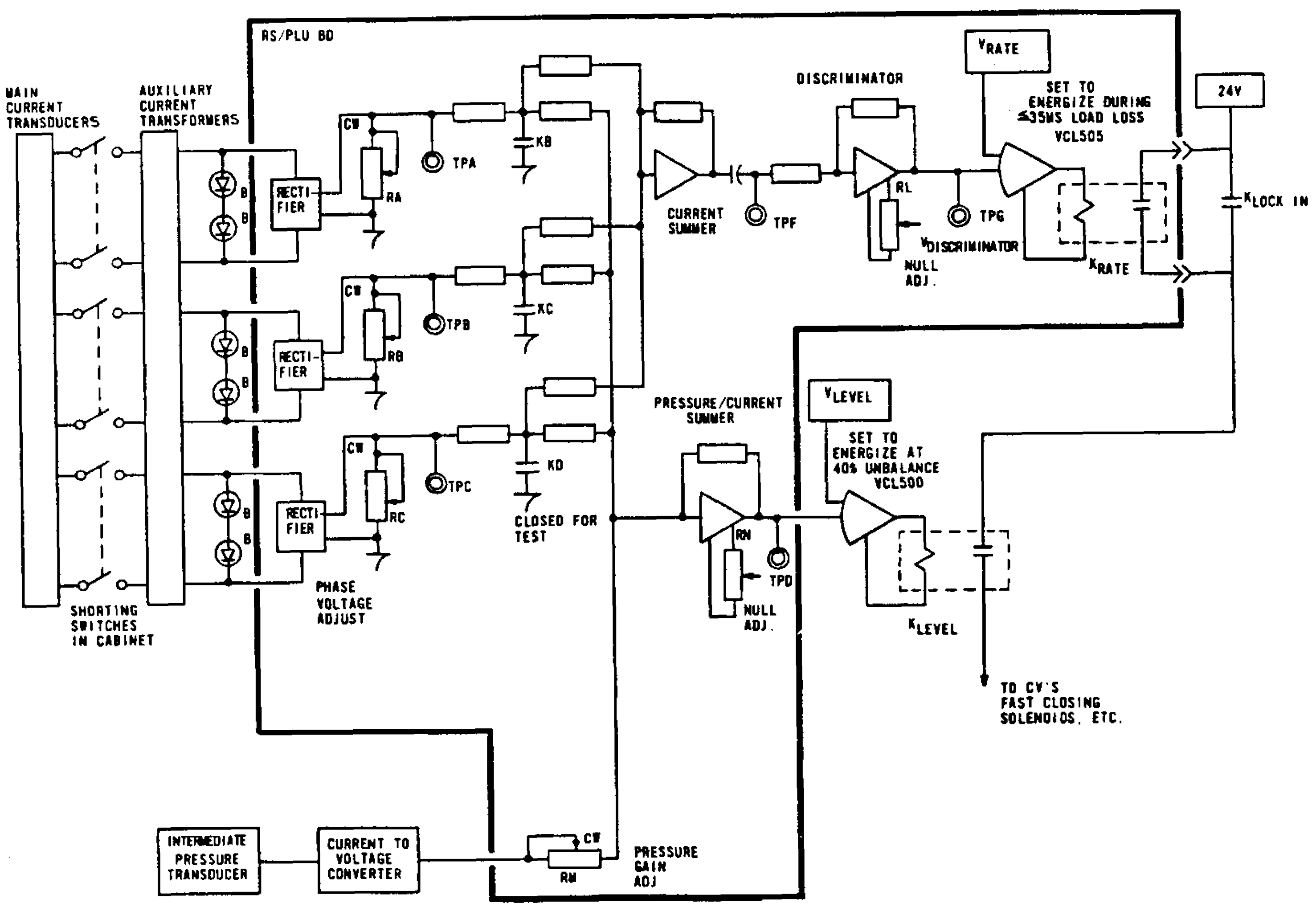
Figure 10.2-5 replaced by dwg.
M2J-101, Sh. 5

FSAR FIGURE 10.2-5, Rev. 54

PPL DRAWING FF110691, Sh. 105



Rate-Sensitive P/L Unbalance Control Logic



Rate-Sensitive Power/Load Unbalance Circuit

FSAR REV. 48, 12/94

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 AND 2
FINAL SAFETY ANALYSIS REPORT

RATE SENSITIVE POWER/LOAD UNBALANCE CIRCUIT

FSAR FIGURE 10.2-6

PP&L DRAWING

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FSAR REV. 53, 4/99

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UNITS 1 AND 2
FINAL SAFETY ANALYSIS REPORT

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FSAR FIGURE 10.2-7

PP&L DRAWING FF110680, sh 2401

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FSAR REV. 53, 4/99

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 AND 2
FINAL SAFETY ANALYSIS REPORT

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FSAR FIGURE 10.2-8

PP&L DRAWING FF110691, sh 1101

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FSAR REV. 53, 4/99

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 AND 2
FINAL SAFETY ANALYSIS REPORT

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FSAR FIGURE 10.2-9

PP&L DRAWING FF170139, sh 12

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FSAR REV. 53, 4/99

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 AND 2
FINAL SAFETY ANALYSIS REPORT

Figure Deleted

FSAR FIGURE 10.2-10

PP&L DRAWING FF110680, sh 3301

THIS FIGURE HAS BEEN

REPLACED BY DWG.

M-133, Sh. 1

FSAR REV. 58

SUSQUEHANNA STEAM ELECTRIC STATION **UNITS 1 AND 2** **FINAL SAFETY ANALYSIS REPORT**
Figure 10.2-11 replaced by dwg. **M-133, Sh. 1**
FSAR FIGURE 10.2-11, Rev. 49

PPL DRAWING E106238, Sh. 1

10.3 MAIN STEAM SUPPLY SYSTEM

The main steam supply system for this BWR cycle extends from the outermost containment isolation valve up to but not including the turbine stop valves and includes connected piping of 2-1/2 inches nominal diameter or larger up to and including the first valve that is either normally closed or is capable of automatic closure during all modes of reactor operation.

10.3.1 DESIGN BASES

The main steam supply system has no safety-related function and is designed to:

1) Deliver the required steam flow from the reactor to the turbine generator, at rated temperature and pressure, over the full range of operation from turbine warm up to valves wide open (VWO).

2) Provide motive steam to the steam jet air ejectors.

3) Provide steam for the steam seal evaporator and driving steam for reactor feed pump turbines.

4) Provide steam for the off gas recombiner.

5) Bypass reactor steam to the condensers during startup and any time the quantity of steam produced by the reactor is more than is required by the turbine generator.

10.3.2 DESCRIPTION

The design pressure/temperature rating of the main steam piping is 1230 psig at 585EF. The piping is designed and tested according to ASME Section III, Class 2, and is fabricated of seamless carbon steel (the 24 inch lines are SA106 Grade C, all other sizes are either SA106 Grade B or an alloy steel that provides increased resistance to erosion/corrosion.

There are four 24 inch nominal main steamlines supplying steam to the turbine generator. Each line is provided with a drain downstream of the outermost containment isolation valve. The drains are routed to the condenser through a common 3 inch header. The main steam line drain can be used to process leakage from the outboard Main Steam Isolation Valves (MSIV). The Isolated Condenser Treatment Method (ICTM) routes leakage past MSIVs to the main condenser utilizing the main steam drain lines as a pathway. In the condenser, volumetric dilution and plate-out hold up fission products until eventual release to the environment through the low pressure turbine seals. The design of the ICTM is such that 300 scfh of total MSIV leakage can be processed with the resulting radiological dose consequences bounded by the DBA-LOCA dose analysis (see Section 6.7). Additional leakage above 300 scfh can be processed by this with a corresponding fractional increase in offsite and control room doses. Each main steamline is also provided with low point drains consisting of a drip leg which, under normal operation, collects moisture and drains it to the condenser through a normally open valve and a restricting orifice. Each drip pot is provided with high and low level switches which operate another motorized drain valve that is normally closed and is installed in parallel to the normally open valve described above. On high level the level switch opens the motorized valve and drains the moisture directly to the condenser. When the level in the drip leg has been lowered sufficiently the low level switch closes the valve.

Pressure equalizing lines, 24 inch nominal size, branch from each main steamline and connect to a 24 inch nominal header which ties into the bypass valve chest through two 18 inch nominal lines. The 24 inch header is provided with a drip pot similar to that described for the main steamlines. The main steam supply to the reactor feed pump turbines originates from this 24 inch header.

See Dwgs. M-101, Sh. 1, M-101, Sh. 2 and M-101, Sh. 3 for details of the above description. For details of piping downstream of the turbine stop and control valves see Section 10.2.

During normal plant operation the turbine control valves and bypass valves are controlled by one of two pressure regulators furnished by the turbine vendor. These two regulators receive the pressure signals from two essentially identical pressure transmitters which are installed in an averaging manifold connected across all four of the main steamlines in accordance with the turbine vendor's instructions. The regulator with the lowest set point will be the controlling regulator until it fails, then the other regulator which is biased approximately 3 psi higher will take over. A pressure transmitter is installed in one of the main steam lines, the readings from which are recorded in the control room.

10.3.3 EVALUATION

The main steamlines (MSL) from the outer isolation valves up to and including the turbine stop valves and all branch lines 2-1/2 inches in diameter and larger, up to and including the first valve (including their restraints) are designed by the use of an appropriate dynamic seismic-system analysis to withstand the Operating Bases Earthquake (OBE) and Safe Shutdown Earthquake (SSE) design loads in combination with other appropriate loads, within the limits specified for Class 2 pipe in the ASME Section III. The mathematical model for the dynamic seismic analyses of the MSL and branch line piping includes the turbine stop valves and piping beyond the stop valves including the piping to the turbine casing. The dynamic input loads for design of the main steamlines are derived from a time history model analysis or an equivalent method, as described in Section 3.9, of the Containment, Reactor Building, Turbine Building and turbine pedestal. The Turbine Building, housing the main steamlines, may undergo some plastic deformation under the SSE, however, the plastic deformation is limited to a ductility factor of 2 and an elastic multi-degree-of-freedom system analysis is used to determine the input to the main steamlines. The stress allowable and associated deformation limits for piping are in accordance with ASME Section III, Class 2 requirements for the OBE and SSE loading combinations. The main steamline supporting structures (those portions of the Turbine Building) are such that the main steamlines and their supports can maintain their integrity within the ASME Section III, Class 2 requirements under the Seismic Category I loading conditions. The pipe supports for the main steamline meet the requirements of ASME Section III 1971 Edition through winter 1972 Addenda, for materials, fabrication and inspection.

Between the outermost isolation valves and the turbine stop valves the four main steamlines are routed within the confines of a tunnel. Temperature elements are located at each end of this tunnel and the readings from these are fed into a temperature differential switch. The purpose of these temperature elements is to detect a failure of any of the main steamlines. This would be indicated by an increase in the temperature differential which would be sensed and an alarm initiated.

For details of the analysis of postulated high energy lines failure refer to Section 3.6.

10.3.4 INSPECTION AND TESTING REQUIREMENTS

The main steamlines outboard of the outermost MSIV are fabricated, examined and tested in accordance with the ASME Boiler and Pressure Vessel Code, Section III, Class 2.

The main turbine stop valves are tested at vendor recommended frequencies as described in FSAR Section 10.2.3.6. Similarly each bypass valve is tested weekly. The preoperational and inservice inspection of the main steamlines is described in Section 6.6. The preoperational and inservice inspection of the steamline isolation valves is described in Subsection 5.2.4. The system was preoperationally tested in accordance with the requirements of Chapter 14.

10.3.5 WATER CHEMISTRY (PWR)

Not applicable

10.3.6 STEAM AND FEEDWATER SYSTEM MATERIALS (NON-NSSS)

10.3.6.1 Fracture Toughness

The ASME Class 2 main steam and feedwater piping was not impact tested. The ASME Class 1 main steam piping was covered by Subsection 5.2.3.3.1. The ASME Class 1 feedwater piping was impact tested in accordance with article NB-2000. The penetrations of these lines through the primary containment, from the isolation valves outside the containment, were charpy, V-notch, or drop weight tested (See Subsection 3.1.2.5.2).

10.3.6.2 Material Selection and Fabrication

1) Materials used in the main steam and feedwater systems are listed in Appendix I to Section III of the ASME Code. Materials for Class 1 main steam piping are covered by Subsection 5.2.3. Material for Class 1 feedwater piping is SA-333gr6. Material for Class 2 main steam and feedwater piping is SA-155 KC70, SA-106 gr B or C, and A335 gr P22 material that provides increased resistance to erosion/corrosion.

2) With the exception of certain 1 sensing lines, there are no austenitic stainless steel piping components in this system.

3) The cleaning and handling Class 2 and 3 components will be performed in accordance with cleanliness Specification 8850-M-167 which complies with the requirements of Regulatory Guide 1.37, March 16, 1973 and ANSI N45.2.1-73.

4) There is no low alloy steel in these systems.

5) Exceptions to Regulatory Guide 1.71 are described in Section 3.13.

10.4 OTHER FEATURES OF THE STEAM AND POWER CONVERSION SYSTEM

10.4.1 MAIN CONDENSER

10.4.1.1 Design Bases

The main condenser has no safety-related function and is designed to:

1) Condense and deaerate the exhaust steam from the main turbine and reactor feed pump turbines.

2) Accept and deaerate the drains from the feedwater heaters and other components in the heat cycle.

3) Serve as a heat sink for the turbine bypass steam, extraction steamline dump drains and heat cycle relief valve discharges.

4) Retain for a minimum of two minutes the condensate formed during full load operation to allow radioactive decay prior to returning the condensate to the cycle.

10.4.1.2 Description

The main condenser is a triple-pressure deaerating type comprising three (3) separate shells, one Low Pressure (LP), one Intermediate Pressure (IP) and one High Pressure (HP). Each of these shells is connected to the exhaust of one of the three low pressure turbines by a rubber expansion joint which is secured between two steel frames, one being welded to the turbine exhaust and the other to the condenser. The condensers are provided with deaerating hotwells which remove air plus hydrogen and oxygen formed in the turbine steam due to the disassociation of water in the reactor.

These non-condensible gases are concentrated in the air cooling sections of the condensers, where they are removed by the steam jet air ejector and discharged to the gaseous radwaste system. (See Subsection 10.4.2)

The steam exhausted to the condenser is condensed by water which is circulated through the condenser tubes by pumps which take their suction from the cooling tower basin (see Subsection 10.4.5).

The oxygen content of the condensate is designed not to exceed 0.005 cc/l as measured at the discharge of the condensate pumps with an air in leakage of up to 75 cfm. Design parameters for the condensers are shown in Table 10.4-1. The condenser is designed and built to the standards of the Heat Exchange Institute and the manufacturer's standard practice.

10.4.1.3 Safety Evaluation

The main condensers are not required either to support the safe shutdown of the reactor or to perform in the operation of any reactor safety features.

The anticipated inventory of radioactive contaminants during both operation and shutdown is discussed in Sections 11.1 and 11.3. The shielding and controlled access arrangement for the main condensers is described in Section 12.3.

10.4.1.3.1 Radioactive Gases

Under normal operation, these gases are removed by the air ejector and delivered to the gaseous radwaste system. To prevent unacceptable accidental releases of radioactivity to the environment, the ventilation system maintains a slight vacuum in the condenser area. Any radioactive gases which leak out of the condenser are removed by the ventilation system and processed through charcoal filters before being vented out of the turbine building stack. Any hydrogen which accumulates in the condenser during operation is removed as described in Subsection 10.4.1.2. There will be no significant buildup of hydrogen in the main condenser during shutdown as it will be isolated from potential sources of hydrogen.

10.4.1.3.2 Condenser Leakage

If one or more condenser tubes develop leaks or if a tube to tubesheet joint fails, the circulating water will be forced into the condensate, thus raising its conductivity. To detect this condition, conductivity quality is continuously monitored by a conductivity analyzer on a continuously flowing sample from the inlet header to the condensate polishers. Conductivity is recorded by the Water Chemistry Data Acquisition System and in the control room. High conductivity is indicated by a local alarm light and by an alarm in the control room. Plant operators have immediate access to data on condensate quality.

The water boxes and crossover piping are made of carbon steel and designed for a pressure of 90 psig. Tubesheets are carbon steel. The tubesheets, waterboxes and crossover piping are coated with an epoxy to minimize corrosion. The condenser tubes, baffles, distribution headers, impingement plates, spray pipes, etc., are type 304 stainless steel.

All high-velocity or flashing steam-and-water mixtures such as drains, dumps and turbine bypass blowdown connections are provided with suitable type 304SS impingement baffles and/or perforated distribution pipes to prevent tube erosion and preclude cutting of structural members.

10.4.1.3.3 Circulating Water System Rupture

The presence of any water accumulation in the condenser area is detected by level switches which are mounted on the shielding wall at various points around its perimeter. These switches will alarm in the control room.

The flooding caused by a major leak such as the complete rupture of a rubber expansion joint will be contained within the concrete shielding walls which surround the condenser area and which are designed to withstand the possible 20 feet of differential water pressure they could experience in the event of a major rupture.

Elevation 656' doors which provide access through the shielding walls, are pressure resistant. While not watertight, these doors will restrict water leakage out of the condenser bay in the event of flooding. Also, while penetrations through the walls are not watertight, they are filled with a sealant for radiation shine which will serve to limit the quantity of water leaking out of the condenser area in the event that it becomes flooded. During a major rupture of an expansion joint, the water could rise from the condenser area floor at el. 656 to grade at el. 676, at which level it will spill out through the doors. There is no safety-related equipment in the Turbine Building below grade, and the penetrations below grade, between the Turbine building and the Reactor Building, are designed to prevent flooding of the Reactor Building. Regular inspections will be made of all the rubber expansion joints in an effort to detect any signs of deterioration which could lead to a major rupture, and any time the system is subjected to a major transient, an additional inspection will be made.

The level instruments will be tested on a regular basis to ensure that they are in good working order. If the hotwell of the condenser ruptured, the 100,000 gallons of condensate released would flood the condenser area to a depth of less than 18 inches. However, neither a major rupture of the circulating water system nor a rupture of the condenser hotwell will have any effect on any safety-related system since no safety-related systems are located within this area.

10.4.1.4 Tests and Inspections

The steam side of each condenser was hydrostatically tested in the field by completely filling each shell with water and inspecting all accessible welds and surfaces for leakage and/or excessive deflection.

The circulating water side of each condenser was hydrostatically tested in the field to a pressure of 95 psig, and all joints and surfaces were inspected for leaks. The tube to tube sheet joints for the whole tube bundle were also checked for leaks at that time. In addition, all the tubes will be subjected to a pneumatic test at 150 psig minimum and nondestructively tested by the eddy current method in accordance with ASTM Standards A249 and A450 by the manufacturer.

The system was preoperationally tested in accordance with the requirements of Chapter 14.

10.4.1.5 Controls and Instrumentation

10.4.1.5.1 Condenser

To ensure the turbine back pressure stays within recommended pressures while the turbine is in operation, instrumentation is installed which will alarm if those pressures are approached and trip the turbine before those pressures are exceeded. In addition, separate switches are installed which close to prevent the bypass valves from opening if the vacuum in the condenser is low. They will remain closed until the vacuum exceeds the switch setting by 1 inch Hg.

To ensure that the level of the condensate in the hotwell remains within acceptable limits, level transmitters are installed which regulate two sources of makeup and the reject control valves to maintain the hotwell level. The 4-inch makeup and 3-inch reject valves regulate the flow of condensate between the condenser and the condensate storage tanks during normal steady state operation and small transients. During large transients in the system, the regulation of the condensate flow between the condenser and the condensate storage tanks is transferred to the 12-inch makeup and 8-inch reject control valves, respectively. Pressure switches are provided to trip the MSIV's closed in the event that condenser pressure approaches recommended pressures.

Motor operated bypass valves are provided for both the make up and reject control valves. If either or both of these control valves fail the make up and/or reject flow will be regulated remote hand switches in the control room. A high-low level switch is provided to alert the control room operator of abnormal hot well levels.

10.4.1.5.2 Condensate Contamination

If any condenser tubes develop leaks at the tubesheets or a condenser tube rupture occurs they are detected by conductivity analyzers on the Turbine Building sample stations for HP, IP, and LP condenser hotwell discharge.

Continuous condenser samples can be extracted from the HP, IP, and LP condenser hotwell discharge pipes. The samples can be analyzed for conductivity levels in the Turbine Building Sample Station as described in Section 9.3.2. HP, IP, and LP condenser hotwell high conductivity is indicated by a light on the sample station and by an output from the Water Chemistry Data Acquisition System as described in Section 9.3.2.

A SF6 gas injection system is installed for gas injection into the Circulating Water System inlet to the condenser water boxes. Gas from the Off Gas System is analyzed for SF6 gas and presence of SF6 gas is indication of a condenser tubesheet or tube leak.

With the arrangement of the HP, IP, and LP condenser hotwell discharge samples to the Turbine Building Sample Station conductivity analyzers and the SF6 gas injection system, condenser tubesheet leaks or tube leaks can be traced to determine which circulating water tube bundle is leaking.

10.4.2 MAIN CONDENSER EVACUATION SYSTEM

10.4.2.1 Design Bases

The Main Condenser Evacuation system has no safety-related function and is designed to:

a) Establish and maintain vacuum on the condenser as required during startup, shutdown and power operation.

b) Remove the noncondensible gases from the main condenser and discharge them to the gaseous radioactive waste system

c) Condense any steam removed from the condenser with the noncondensible gases and return the condensate to the condenser.

10.4.2.2 System Description

The major components of the main condenser evacuation system are a mechanical vacuum pump and steam jet air ejectors. These function as follows:

Mechanical Vacuum Pump - The mechanical vacuum pump is used during startup (at ≤ 5% power) and shutdown (at ≤ 5% power) to establish and maintain when main steam or auxiliary boiler steam is not available to operate the steam jet air ejectors. The vacuum pump discharges the air drawn from the condenser to atmosphere through the plant ventilation stack.

The mechanical vacuum pump and its suction valve are operated remotely from the control room. The suction valve is automatically closed upon a main steam high radiation signal. The pump is shutdown on high radiation or low seal water flow to the pump. A water separator removes the water droplets from the noncondensible gases before discharging them to atmosphere.

The capacity of the vacuum pump is 4000 scfm and it is designed to evacuate the main condenser to 5 inches Hg Absolute within 90 minutes.

Since the pump components are manufacturer's standard items, they are not ordered per a specific ASTM, ANSI or ASME code or standard.

Steam Jet Air Ejectors (SJAE) - Once vacuum has been established by the mechanical vacuum pump, the steam jet air ejector is placed in service to maintain vacuum and the mechanical vacuum pump is shut down. The air ejector is a full capacity 2-stage unit with four 25 percent capacity first stage ejectors and one full capacity second-stage ejector with a rated capacity at 130°F and 14.7 psia of 75 scfm air, 160 scfm hydrogen and 80 scfm oxygen.

The four first-stage steam jet ejectors continuously remove noncondensible gases and some steam from the condenser and discharge them to the intercondenser where the carryover steam is condensed and returned to the condenser. The gases are then removed from the intercondenser by the second-stage ejector and discharged to the off gas recombiner system together with the second-stage ejector motive steam. This steam and gas mixture eliminates the possibility of an explosion in the line even though a mixture rich in hydrogen is present. The ejectors require motive steam at 110 psig to operate. This is obtained either from main steam, which is nominally at 1000 psia and must therefore be reduced in pressure through pressure reducing valves, or from steam produced by the auxiliary boilers through a separate control valve. There are two redundant pressure-reducing valves, either of which can be used to provide motive steam. Steam for additional off-gas dilution is provided in a bypass piping loop around the second stage air ejector. Control is provided by two full capacity parallel flow control loops. The controls are designed to provide an effluent hydrogen concentration of less than 4% by volume at 100% rated reactor power which maintains the downstream equipment within the equipment design temperature limits. Upon a reduction of approximately 15% of the required steam flow, the first stage air ejector gas inlet valves are closed by the off gas recombiner isolation logic.

Condensate taken from the condenser hotwell by the condensate pumps and discharged to the condensate system is used as the cooling medium for the air ejector intercondenser.

Both stages of air ejectors have nominal pressure ratings of 15 psig. The intercondenser has a pressure rating of 50 psig. An intercondenser relief valve is provided and is set to relieve full flow at 16.5 psig. The first stage ejectors and intercondenser operate at less than 10 psia. The second stage ejectors operate between 10 psia and 2 psig.

The intercondenser is manufactured to Section VIII of the ASME Boiler and Pressure Vessel Code. The complete system is shown on Dwgs. M-107, Sh. 1, M-107, Sh. 2, M-107, Sh. 3, and M-107, Sh. 4.

10.4.2.3 Safety Evaluation

The noncondensible gases in the main condenser are removed by the air ejectors and delivered to the gaseous radioactive waste system. These gases normally include the following: nitrogen-16, oxygen-19 and nitrogen-13, plus the radioactive noble gas parents of strontium-89, strontium-90 and cesium-137. The largest contribution to the main condenser's off-gas activity will come from the nitrogen-16 source.

For an evaluation of radioactive contaminants in the effluent from the steam jet air ejectors and the associated doses, see Section 11.3.

10.4.2.4 Tests and Inspections

All shop tests and inspections for the intercondenser were in accordance with Section VIII of the ASME Boiler and Pressure Vessel Code.

The vacuum pumps were tested as completely assembled units.

The system was preoperationally tested in accordance with the requirements of Chapter 14.

10.4.2.5 Controls and Instrumentation

Both the steam jet air ejectors and the mechanical vacuum pump are controlled from the control room. In placing the air ejectors into service, interlocks are provided to minimize thermal shocks and prevent intercondenser overpressurization.

The valve sequence is as follows:

(1) Open the second stage ejector discharge, HV-10721;

(2) Open the second stage ejector steam inlet, HV-10702;

(3) Open both the main steam isolation valve, HV-10107, and the control valves, HV-10701 A and B;

(4) Open the first stage ejector steam inlet, HV-10722; and

(5) Open the condenser off gas isolation valves, HV-10716 through 19.

In lieu of opening the main steam valves, auxiliary steam can be used by opening HV-10752. All valves will close simultaneously upon closure initiation of HV-10721.

The noncondensible gases in the outlet line from the intercondenser are monitored by a pressure transmitter and a temperature transmitter both of which read out in the control room. In addition, a pressure switch is provided which on high pressure in the line indicates as a trouble alarm in the control room. The discharge line from the secondary ejector is provided with a pressure transmitter which reads out in the control room and a pressure switch which on high pressure indicates as a trouble alarm in the control room.

The pressure in the motive steamline to both the primary ejector and secondary ejector is sensed by a pressure switch which alarms on high pressure at a local panel. A pressure indicator in the control room also monitors the steam supply.

The vacuum pump, the seal water pump and the air suction valve are all operated from a common handswitch in the control room. When this switch is energized the seal water pump starts and the air suction valve opens. After approximately 150 seconds the vacuum pump starts, providing the flow switch in the seal water supply to the vacuum pump is indicating there is sufficient flow.

A flow switch is located in the line supplying seal water to the vacuum pump from the seal water cooler. This switch trips the pump in the event of low seal water flow to the pump.

The mechanical pump will be shut down automatically on receipt of a main steam high radiation signal.

10.4.3 STEAM SEAL SYSTEM

10.4.3.1 Design Bases

The steam seal system has no safety-related function and is designed to provide a continuous supply of steam (low level radioactive) to main turbine shaft seals, the stem packings of the stop valves, control valves, combined intermediate valves and bypass valves, the shaft seals of the reactor feed pump turbines and the stem packing of the reactor feed pump turbines, stop and control valves.

The purpose of this sealing steam is to prevent air leaking into the cycle and radioactive steam leaking out of the cycle into the Turbine Building.

The steam seal evaporator, in which the steam is generated, is designed, fabricated, tested and stamped in accordance with Section VIII of the ASME Boiler and Pressure Vessel Code. The steam seal system piping material is carbon steel ASTM A106 Grade B. Where ISI inspections have detected wall thinning, the piping material has been replaced with ASTM A-335 Grade P-22, a more wear resistant material.

10.4.3.2 Description

The steam (low level radioactive) for the seals is generated in the steam seal evaporator by heating condensate with radioactive steam. The evaporator is a horizontal shell and U-tube heat exchanger in which the radioactive steam is passed through the U-tube bundle which is totally immersed in condensate. The condensate for the evaporator is taken from the condensate system from a point downstream of the condensate demineralizer, and the radioactive heating steam is taken either from a main steamline or from the extraction steamline to heaters 3A, 3B and 3C. A backup source of sealing steam is available from the auxiliary boilers. For more detail on the operation of these various steam sources, see subsection 10.4.3.5.

The sealing function is provided by supplying low level radioactive steam at 19 psia to the turbine shaft seals and various valve stems. Of the sealing steam entering the turbine shaft seals, some leaks inward towards the turbine, but some leaks towards the outside, where it enters a vent annulus which is maintained at a slight vacuum (about 11 to 13 inches of water) by the steam packing exhauster. A small amount of air is drawn into this vent annulus from the outside, and this air, together with the sealing steam, is drawn to the steam packing exhauster where the steam is condensed and returned to the condenser. The cooling medium for condensing the steam is the condensate system. The saturated air is discharged by the exhauster to the Turbine Building vent. With this arrangement, all radioactive steam is contained within the turbine loop.

10.4.3.3 Safety Evaluation

The steam seal system is designed to provide the required quantity of sealing steam under all modes of operation. The individual components of the system have been designed to ensure that the steam and air mixture going to the steam packing exhauster is, as far as possible, minimally radioactive. In the event of the loss of the normal source for the steam seal system, an alternate source of sealing steam is the auxiliary boilers. Therefore, radioactive releases to the environment are substantially reduced. Steam from these boilers will be fed directly into the steam seal supply header after its pressure is reduced to 19 psia by a pressure reducing valve.

Protection against overpressure is provided for both the heating steam (tube) side and the condensate (shell) side of the evaporator by the installation of relief valves. Similarly, the steam seal supply header is protected against overpressure by relief valves. All these relief valves discharge to the main condensers.

The steam packing exhauster condenser is provided with two full-capacity exhausters for redundancy.

10.4.3.4 Tests and Inspections

The steam seal evaporator was fabricated and tested to Section VIII, Division I of the ASME Boiler and Pressure Vessel Code. The piping furnished by the Owner was inspected and tested in accordance with ANSI B31.1 and the piping furnished by the turbine vendor, General Electric (GE), was inspected and tested in accordance with their own standards.

Both the shell side and the tube side of the steam packing exhauster condenser was tested to GE requirements.

The system was preoperationally tested in accordance with the requirements of Chapter 14.

10.4.3.5 Controls and Instrumentation

Evaporator Steam Heating System - During low load operation (startup and shutdown), the heating steam for the steam seal evaporator is taken from the main steam lines ahead of the turbine stop valves. Its pressure is reduced by throttling the two main steam supply to sealing steam evaporator (SSE) regulating valves which are 4 inches and 8 inches, respectively. With main steam pressure of 250 psig or more, the 4-inch regulating valve will automatically supply sufficient heating steam to the evaporator to generate the required flow of sealing steam to seal the shaft packings when these packings have normal clearances. With very low main steam pressures or worn packings, the 8 inch regulating valve automatically operates in parallel with the 4 inch valve to provide the additional heating steam required to produce the required steam seal flow in the evaporator. Both regulating valves on main steam supply line fail open on loss of supply air and if a failure occurs, the evaporator steam supply can be controlled from the control room manually by throttling a motor operated valve for a short time until the air supply can be reestablished or the auxiliary steam supply can be put into service.

Evaporator Feed Water System - The level of condensate in the evaporator is maintained within the required limits by a control valve, the operation of which is regulated by signals from a remote proportional controller. In addition to this control valve, the evaporator feedwater isolating valve, which is normally open, and the evaporator feedwater bypass valve, which is normally closed, can be used to control the flow of condensate to the evaporator if the automatic control system malfunctions. The automatic control system is monitored by the evaporator low level and high level alarm. In addition, a high level switch closes the evaporator feedwater isolation valve. The operation of all isolation and bypass valves is performed by hand switches located in the control room. The appropriate alarms and level indicators read out in the control room.

Steam Seal Header - The sealing steam generated in the evaporator enters the steam seal supply header through the pressure control valve which is set to maintain the pressure of the sealing steam at about 4 psig (19 psia). Redundancy for this pressure control valve is provided by a motor operated bypass valve which would be regulated manually from the control room to maintain the pressure of the sealing steam if the pressure control valve fails.

A pressure transmitter in the steam seal header which reads out in the control room will indicate to the operator when to adjust the bypass valve. The steam seal header is also provided with a high-low pressure switch which alarms in the control room.

If there should be a malfunction in the primary steam seal supply system which causes the pressure in the steam seal header to drop, a pressure switch will open the isolating valve and admit auxiliary steam to the steam seal header at 4 psig. This pressure is regulated automatically by another pressure control valve located in the auxiliary steamline.

Evaporator Drain System - The heating steam to the evaporator condenses in the tube bundle and collects in the evaporator drain tank. Under normal operation, the low level controller positions the level control valve to regulate the drain flow to feedwater heaters 2A, 2B and 2C and maintain the drain tank level. If for any reason the flow cannot be handled by this primary drain system and the level in the drain tank continues to rise, the high level controller will open a second level control valve which will allow the excess drains to flow to the high pressure condenser, thereby restoring the level in the drain tank to normal.

In addition to the level controllers, the drain tank is provided with low and high level switches which alarm in the control room.

10.4.4 TURBINE BYPASS SYSTEM

10.4.4.1 Design Bases

The turbine bypass system has no safety-related functions.
The turbine bypass system is designed to bypass main steam directly to the condenser to control the pressure in the reactor during the following modes of operation:

1) Reactor vessel heat up to rated pressure and subsequent cooldown.

2) Turbine run up and run down.

3) Power operation when the quantity of steam generated by the reactor exceeds that required by the turbine.

The piping which connects the main steamlines to the inlet of the bypass valve chest is designed in accordance with ASME Section III Class 2 requirements and the piping connecting the discharge of the bypass valves to the condensers is designed to ANSI B31.1.

The bypass valves are required to have regulation capability and a fast-opening response approximately equivalent to the fast closure of the turbine stop and control valves.

The bypass valves are designed to GE's nuclear standards.

10.4.4.2 System Description

The turbine bypass system Dwgs. M-101, Sh. 1, M-101, Sh. 2, and M-101, Sh. 3 for Unit 1 and Dwgs. M2101, Sh. 1, M2101, Sh. 2 and M2101, Sh. 3 for Unit 2 consists of:

a) Bypass valves

b) Piping between the main steamlines and the bypass valve inlets

c) Piping between the discharges of the bypass valves and the condensers

d) Pressure reducer assemblies.

The bypass valve chest consists of five separate bypass control valves mounted in individual compartments of a common valve chest. The valves are globe type with the stems arranged so that they reach the outside of the chest through the discharge chamber of the respective valve. This minimizes leakage when the valves are closed since it is necessary only to seal the stem against condenser vacuum. The valves open sequentially during startup and shutdown. However, in the event of a full load rejection, such as would occur if the generator circuit breaker opened, it is necessary that all 5 valves open to bypass at least 22 percent of the reactor rated flow

Bypass steam flows from the main steamlines through a 24 inch header, which is upstream of the bypass valves, divides into two 18 inch headers each of which is connected to the valve chest at opposite ends. The discharge connections of the bypass valves are piped individually to the condensers in 10" lines and, in order to reduce the pressure at which the bypassed steam enters the respective condenser, a pressure reducer assembly is installed in each bypass valve discharge line. The pressure reducing assembly consists of a fabricated piece of pipe 6 feet long which increases in size over its length from 10 inch nominal pipe size at the inlet end to 18 inch nominal pipe size at the outlet. This assembly contains four pressure breakdown plates along its length.

The condensers are designed to accommodate the maximum turbine bypass flow (3,672,000 lb/hr total), which is reduced to approximately 250 psig at 1190.3 BTU/lb through the pressure breakdown assemblies, without increasing the turbine backpressure to the turbine trip (stop valve closure) setting of 21.7 inches Hg vacuum. The bypass flow enters the condenser below the tube bundle to assure steam desuperheating.

10.4.4.3 Safety Evaluation

With 7 inches Hg vacuum and vacuum decreasing in the condenser, the bypass valve vacuum trip pressure switches will close to prevent the bypass valves from opening. These pressure switches will remain closed until the vacuum exceeds the bypass valve trip setting (7 inches Hg vacuum) by 1 inch. At this time the circuit automatically resets and permits the bypass valves to open.

There are no safety-related components in the vicinity of the bypass piping. A high energy line failure in the turbine bypass system could cause a trip of the main turbine either due to high condenser pressure because of increased air in-leakage at the break or a possible break of EHC system piping due to steam impingement. Loss of EHC cannot cause overspeed but may cause a turbine trip.

Failure of the bypass valves to open for any reason, such as a mechanical malfunction or insufficient vacuum in the condenser, will cause the pressure in the reactor to increase, ultimately scramming the reactor and lifting the safety relief valves which discharge the excess steam to the suppression pool. A bypass system failure will have no adverse effect on safety-related components or systems.

The effect of such a situation on the reactor coolant system is described in Chapter 15.

10.4.4.4 Tests and Inspections

The piping upstream of the bypass valve chest, which connects the main steamlines to the bypass valve inlets, was inspected and tested according to ASME Section III, Class 2. The piping downstream of the bypass valve chest, which connects the discharge of each bypass valve individually to the respective condenser nozzle, was inspected and tested according to ANSI B31.1.

Each pressure reducer assembly was hydrostatically tested to 1400 psig by General Electric.

During normal plant operation each bypass valve can be tested from the control room to ensure it is functioning correctly.
The system was preoperationally tested in accordance with the requirements of Chapter 14.

10.4.4.5 Controls and Instrumentation

Controls and valves are designed so that the bypass valves steam flow is shut off if the control system loses its electric power or hydraulic system pressure. For testing the bypass valves during operation, the stroke time of the individual valves is increased during testing to limit the rate of bypass flow increase and decrease to approximately l% per second of reactor rated flow.

Upon turbine trip or generator load rejection, the start of the bypass valve steam flow will not be delayed more than 0.1 second after the start of the stop valve or the control valve fast closure motion. A minimum of 80% of the rated bypass capacity will be established within 0.3 second (Turbine Bypass System response time) after the start of the stop valve or the control valve closure motion. For more detail, refer to Subsection 7.7.1.5.

10.4.5 CIRCULATING WATER SYSTEM

10.4.5.1 Design Bases

The circulating water system has no safety-related functions and is designed to remove the latent heat from the main condenser and sensible heat from the service water system and dissipate both in a hyperbolic natural draft cooling tower.

		Unit 1	Unit 2
Heat load from main condenser (100% power)	=	8.960×10^9 BTU/Hr	8.944×10^9 BTU/Hr
Heat load from service water system	=	0.188×10^9 BTU/Hr	0.188×10^9 BTU/Hr
Design Heat Load (100% power)	=	9.148×10^9 BTU/Hr	9.132×10^9 BTU/Hr

10.4.5.2 System Description

The circulating water system consists of the following major components.

a) 1 - Cooling Tower rated to remove a heat load of $8.07x10^9$ Btu/Hr.

b) 4 - 25% capacity circulating water pumps each rated 121,000 gpm at 103.6 ft head.

c) 1 - Condenser Tube Cleaning System comprising
2 - Ball strainer sections
4 - Ball circulating pumps each rated 260 gpm at 75ft head
4 - Ball collecting baskets
16 - Ball injection nozzles
2 - Control Panels

d) Piping, valves, controls and instrumentation.

Circulating water from the cold water outlet of the cooling tower basin is delivered to the suctions of the four circulating water pumps through two 108 inch diameter pipes. Each of these pipes supply one pair of pumps. Each pair of pumps discharge to a 96 inch header and the two 96 inch headers are run underground into the condenser area. Here each of these headers divides into two 78 inch lines one pair being connected to the A and B quadrants and the other to the C and D quadrants circulating water inlet connections of the Low Pressure (LP) Condenser. The circulating water discharging from the LP condenser flows into the Intermediate Pressure (IP) Condenser and subsequently to the High Pressure (HP) Condenser in series. From the discharge of the HP Condenser each pair of 78 inch lines is combined into one of two 96 inch headers which return the circulating water to the cooling tower.

The circulating water pumps are the horizontal centrifugal type and driven by electric motors. Motorized butterfly valves are provided in the suction and discharge of each pump so that the pump can be isolated if necessary. Motorized butterfly valves are also provided in each of the 78 inch circulating water lines, one at the inlet to the LP Condenser and another at the outlet from the HP Condenser. These permit any of the four quadrants on the circulating water side (tubeside) of the condensers to be isolated in the event of tube leakage. Rubber expansion joints are provided at the suction and discharge of each circulating water pump and at the inlet and outlet connections of each of the three condensers.

The condenser tube cleaning system is built into the circulating water system. It operates by injecting foam rubber balls, whose diameter is slightly larger than that of the tubes, into the four CW lines entering the LP Condenser. The flow of water drives these balls through the tubes of each condenser in turn and since they are larger in diameter than the tubes they scour the inside of the tubes & keep them free of algae, etc. The balls emerge in the CW lines at the outlet from the HP Condenser and they are collected in full flow strainers which are installed in the 96 inch CW discharge lines.

Recirculation pumps draw off the balls from the strainers together with a small quantity of water and reinject them back into the LP Condenser inlet. The strainers can automatically reverse for backwashing on high pressure drop across the strainer. As part of the backwash cycle, the balls are removed from service automatically and collected in specially designed ball collectors. The screens are repositioned so that any collected debris is returned to the cooling tower basin.

The circulating water is chemically treated to prevent the formation of biological growth, and to control PH.

Water lost from the system due to evaporation and drift from the cooling tower is replenished by water pumped from the Susquehanna River by the make up pumps.

The service water system is described in Subsection 9.2.1.

A corrosion monitoring station is available in each unit's circulating water system. The non-permanent equipment available at the station is used to monitor and control of calcium carbonate scaling, monitor the effectiveness of dispersants used to prevent fouling, monitor control of biological fouling and monitor the effectiveness of condenser tubing corrosion control in this system. Stainless steel piping is used for the sample lines to and from the station to maximize their useful service life. Piping is sized to achieve the required circulating water flow through the sample stations during normal system operation.

10.4.5.3 Safety Evaluation

The potential for flooding due to an expansion joint rupture is discussed in Subsection 10.4.1.

The opening and closing times of the circulating pump discharge valves have been arranged to minimize system transients when a pump is started. On trip of one or more of the four circulating water pumps due to an abnormal electrical condition, the reactor recirculation pumps will run back to the low speed stop resulting in about 62 mlb / hr core flow and about 74% rated reactor power.

Failure of the cooling towers will not affect any safety-related systems.

10.4.5.4 Tests and Inspections

The condenser was tested as described in Subsection 10.4.1.4. The pumps, butterfly valves, expansion joints and tube cleaning system were all tested in accordance with the applicable specification by their respective manufacturers prior to shipment.

Hydrostatic and leakage tests were performed on the circulating water pipe in accordance with AWWA standards.

The system was preoperationally tested in accordance with the requirements of Chapter 14.

10.4.5.5 Controls and Instrumentation

Level elements are located upstream and downstream of the screens in the cooling tower basin outlet. The upstream side level element initiates high and low level alarms; the downstream side initiates a low level alarm. A differential level switch alarms on high level differential across the screens indicating that they require cleaning. Low level switches sense level in the basin outlet downstream of the screens and upstream of the inlet to the 108 in. diameter CW pump suction piping. On low-low level these switches alarm in the control room and operator action is required to trip all four circulating water pumps manually. The low-low level also will prevent any of the four circulating water pumps from being started.

The pressure at both the suction and discharge of each pair of CW pumps is monitored by pressure transmitters which read out in the control room.

The bearings of each pump and motor are provided with RTD’s that alarm on high temperature. In addition the temperatures of the windings of each motor are monitored by RTD's that alarm on high temperature.

Pressure transmitters are installed in each of the four CW inlet connections on the LP Condenser and in the four outlet connections of the HP Condenser. These are interconnected to monitor the differential pressure across the three condensers on the CW side. Resistance Temperature Detectors (RTD's) are also installed in the LP Condenser waterbox inlets B and D and in all LP, IP, and HP Condenser waterbox outlets to monitor the temperature of the circulating water.

A level controller senses the level in the cooling tower basin, and operates a level control valve, which is in the river water makeup pump discharge line, to maintain the cooling tower basin level.

10.4.6 CONDENSATE CLEANUP SYSTEM

The Condensate Cleanup System is used for filtration and demineralization of the condensate to maintain the required purity in the feedwater and to ensure acceptable reactor water chemistry.

10.4.6.1 Design Bases

The objectives and criteria which form the bases for the design and operation of the Condensate Cleanup System are as follows:

a) The Condensate Cleanup System has no nuclear safety-related functions as a design basis.

b) The condensate demineralizers are designed to maintain the condensate at the required purity by removal of the following contaminants:

    1) Products resulting from corrosion that occur in the main steam and turbine extraction piping, feedwater heater shells, drains, and the condensers and hotwells;

    2) Suspended and dissolved solids that may be introduced by small leakage of circulating water through condenser tubes;

    3) Fission and activation products that are entrained in reactor steam and retained in condensate leaving the hotwell; and

    4) Impurities carried into the condenser by makeup water and miscellaneous drains.

c) The system was originally designed based on the influent concentrations given in Table 5.2-5 Location 1. With the influent quality listed in Table 5.2-5 Location 1, the demineralizers were designed not to exceed the quality criteria listed in Table 5.2-5 Location 2.

The bases for these limits are the prevention of crud buildup on fuel heat transfer surfaces, the need to minimize the transport of radioactive corrosion products outside the core, and the protection of the reactor coolant pressure boundary.

d) The circulating water quality used in the original design of the Condensate Cleanup System is given in Table 10.4-3.

e) The seismic and quality group classifications of the Condensate Cleanup System components, piping, and structures housing this system are listed in Section 3.2. Piping is furnished in accordance with ANSI B31.1. Pressure vessels that fall within the jurisdiction of ASME Section VIII are furnished in accordance with that Code.

f) The design pressure of the Condensate Cleanup System is 740 psig at 150°F, which is above the shut-off head of the condensate pumps.

g) The system is designed and operated in accordance with the intent of Regulatory Guide 1.56, as discussed in Sections 5.2.3.2.2 and 10.4.6.3.

10.4.6.2 System Description

The P&ID for the Condensate Cleanup System is shown in Dwgs. M-116, Sh. 1, M-116, Sh. 2 and M-116, Sh. 3. The system consists of seven deep bed demineralizer vessels and supporting systems that provide the capability to transfer resins from the demineralizer vessels for cleaning, makeup, and discharge.

The system purifies condensate continuously at temperature ≤140°F, pressure of 550 psig, and at a flow rate of approximately 32,000 gpm. Typically, flow through each demineralizer vessel with the plant at approximately full power operation ranges from approximately 4570 gpm to 5330 gpm depending upon whether seven or six demineralizers are in service. The flow through a demineralizer vessel may be increased up to approximately 5,760 gpm for short periods. Seven vessels are in service during normal full power plant operation. Six bed operation is required when one demineralizer is removed from service for maintenance, resin cleaning or resin replacement.

10.4.6.2.1 Condensate Demineralizers

The condensate demineralizers are utilized in removing ionic impurities and insoluble products (by mechanical filtration, ion exchange, and electrostatic attraction) from the condensate in order to maintain the required purity in the feedwater and ensure acceptable reactor water chemistry. The condensate is pumped from the condenser hotwell by the condensate pumps, through the SJAE condenser the steam packing exhauster condenser, and the condensate filtration system (CFS) before entering the condensate demineralizers. Each demineralizer contains mixed resins ranging in proportion from two parts cation resin to one part anion resin by volume to a 1:1 equivalent capacity ratio of cation to anion resin. The condensate demineralizers are piped directly into the feedwater system and receive condensate flow from the condensate pumps.

The effluent strainer in the discharge piping of each demineralizer protects against reactor water quality degradation resulting from resin discharge in the event of a demineralizer lateral failure.

As needed, the resin beds are transferred from the demineralizer to the external regeneration skid for temporary storage, cleaning and/or discharge. A spare charge of resins may be held in the regeneration skid to support the prompt replacement of a resin bed.

10.4.6.2.2 Supporting Systems

The equipment provided for the addition, cleaning, and disposal of the condensate demineralizer resins is shown in Dwgs. M-116, Sh. 2 and M-116, Sh. 3 and consists of the regeneration skid with an ultrasonic resin cleaner in Unit 1 only.

The functions of the regeneration skid are to:

- allow makeup of resin lost during service, transfer or cleaning;
- discharge of expended resin;
- load, rinse, and mix replacement resin beds;
- permit sampling of resin; and
- provide temporary resin storage in support of demineralizer maintenance and during resin cleaning.

Chemical regeneration is not being performed. Resin is routinely cleaned by the ultrasonic resin cleaner and when exhausted is discharged to the solid waste management system (Section 11.4) for packaging and offsite disposal. The condensate filters remove iron particulates from the condensate system fluid and eliminates the need for ultrasonic resin cleaning of the demineralizer resins during normal operation in Unit 1.

Supporting equipment consists essentially of four main vessels: cation resin regeneration tank (CRT), anion resin regeneration tank (ART), resin storage tank (RST), and in Unit 1 only the ultrasonic resin cleaner (URC).

The regeneration skid is designed for 75 psig and 150°F. Interlocks are provided so that an off-line demineralizer cannot be pressurized unless it is isolated from the regeneration skid. If high pressure occurs in the resin transfer line, an isolation valve in the line will automatically close and a relief valve will open to protect the system. The cation resin regeneration tank serves as a resin receiving, resin cleaning, and resin separation tank for demineralizer resin beds that require cleaning or replacement.

In Unit 1 only, the removal of crud accumulation on the resins is accomplished by the ultrasonic resin cleaner (URC). The URC is used to remove insoluble iron oxides (and associated radionuclides) deposited on the resin and to remove resin fines produced during demineralizer service, resin transfer and cleaning. A typical cleaning sequence begins with the transfer of the resin bed from the demineralizer to the CRT. The CRT is then filled with condensate transfer water and the uncleaned resin is sent to the URC vessel by the addition of condensate transfer water to the CRT. Sluice water is added downstream of the CRT to facilitate the transfer to the URC vessel. In the URC, the resin falls by gravity through a net upward flow provided by a backwash stream of condensate transfer water. Ultrasonic transducers on one side of the URC vessel input ultrasonic energy to the water through which the resin is falling. Cleaned resin beads continue downward and are removed from the collection cone at the bottom by an eductor. Particulates including corrosion products and resin fines are carried upward into the URC waste stream and routed to the solid waste management system.

Each demineralizer is routinely removed from service for resin cleaning and maintenance. Refer to Sections 11.2 and 11.4 for a discussion of the effect of the condensate demineralizers on the liquid and solid waste management systems.

The performance of the system is determined primarily by monitoring reactor water chemistry, since the concentration of impurities in the polisher effluent will be increased by a factor of approximately 100 in the reactor coolant system. In practice, resin is replaced when necessary to maintain acceptable reactor water chemistry. The data from continuous conductivity analyzers on the individual bed outlets as well as specialized chemical analyses and trending are used to identify potentially degraded resin beds.

10.4.6.3 Safety Evaluation

The Condensate Cleanup System has no safety-related function and is not required to be operable following a LOCA. Failure of the system does not compromise any safety-related system or component, or prevent a safe shutdown of the plant.

Required purity in the feedwater and acceptable reactor water chemistry is maintained by assuring that the condensate demineralizers contain enough reserve capacity to permit orderly shutdown of the reactor in the event of a serious condenser leak. This reserve capacity precludes the potential for damage to the reactor coolant pressure boundary or to the core structural internals due to high levels of circulating water impurities.

The system was originally designed such that the effluent water quality stated in Subsection 10.4.6.1 would not be exceeded with an 11.5 gpm condenser leak when circulating water contains 1000 ppm of total dissolved solids. The condensate cleanup system was originally designed to sustain an effluent conductivity of 0.15 µmho/cm with a 46 gpm condenser leak when circulating water contains 1000 ppm of total dissolved solids.

During operation at the first EPU plateau (up 3733 MWth), the demineralizers will experience higher loadings, resulting in reduced run times and potential reduction of effluent quality. The chemistry guidelines/commitments to EPRI, INPO, and BWRVIP, required to protect reactor vessel and fuel integrity, will continue to be met.

The administrative limits on the reactor water chemistry parameters (FSAR Section 5.2.3.2.2) restrict feedwater impurities such that condensate demineralizers are removed from service for cleaning or resin replacement with substantial remaining ion exchange capacity. The Condensate Cleanup System is designed for conductivity endpoint as a indication of demineralizer break through rather than utilizing the methodology described in regulatory position C.4.c of Regulatory Guide 1.56.

Condensate conductivity levels are maintained within the limits of Table 2 of Regulatory Guide 1.56 in the following manner:

Individual demineralizer vessel outlet conductivity is continuously monitored, indicated locally at the Turbine Building Sample Station, and recorded by the Water Chemistry Data Acquisition System. High conductivity, indicating ionic exhaustion, is alarmed locally via an alarm light on the Turbine Building Sample Station. The high conductivity alarm setpoint is $\geq$0.1 µmho/cm, thus a demineralizer with an ionically exhausted resin bed is removed from service and replaced before reaching the lower limit of 0.2 µmho/cm given in Table 2 of Regulatory Guide 1.56 (with a maximum limit of 0.5 µmho/cm which requires immediate corrective action). In addition, the effluent from a cleaned or replacement resin bed is initially recycled to the condenser to ensure that the demineralizer effluent conductivity levels are within acceptable levels prior to placing the demineralizer in service.

The combined demineralizer outlet conductivity is continuously monitored, locally indicated, and recorded by the Water Chemistry Data Acquisition System. High conductivity of the combined effluent is alarmed at ≤0.1 μmho/cm (Modes 1, 2, and 3) locally via an alarm light on the Turbine Building Sample Station. Since each vessel is alarmed when conductivity is 0.065 μmho/cm, the combined effluent is prevented from reaching the alarm point except under conditions of a large condenser leak. Table 2 of Regulatory Guide 1.56 contains a lower limit of 0.1 μmho/cm, and a maximum limit of 0.2 μmho/cm requiring immediate corrective action.

Demineralizer inlet conductivity is similarly monitored, locally indicated, and recorded, with an alarm setpoint of ≥0.1 μmho/cm for identifying condenser leakage. Table 2 of Regulatory Guide 1.56 contains a lower limit of 0.5 μmho/cm, with a maximum limit of 10 μmho/cm requiring immediate corrective action.

10.4.6.4 Tests and Inspections

Piping was inspected and tested in accordance with ANSI B31.1.0. All ASME VIII pressure vessels were hydrostatic tested to 1.5 times their design pressure.

Samples of each batch of new resin are capacity tested. The methods used are those suggested by the resin manufacturer or by ASTM for total exchange capacity.

10.4.6.5 Controls and Instrumentation

The Condensate Cleanup System and supporting equipment are controlled from a local control panel for all modes of operation.

Conductivity is continuously monitored at the outlet of each of the three condenser hotwells, at the common influent and effluent headers of the condensate demineralizers, at the discharge of each demineralizer vessel, and at the common discharge header from the reactor feed pumps. Conductivities are indicated locally at the Turbine Building Sampling Station (Reactor Building Sampling Station for feedwater) and recorded by the Water Chemistry Data Acquisition System. High conductivity alarms are provided to alert the plant operators to an abnormal condition.

A differential pressure transmitter is provided to monitor the differential pressure across the condensate demineralizer system. Flow transmitters, recorders, and flow totalizers are provided at the inlet of each condensate demineralizer. The conductivity cells are periodically checked with an in-line laboratory cell to ensure proper operation. Flow rates are measured at the inlet of each demineralizer vessel and indicated at a local control panel.

10.4.7 CONDENSATE AND FEEDWATER

10.4.7.1 Design Bases

The condensate and feedwater systems have no safety-related functions and are designed to return condensate from the condenser hotwell to the reactor at the required flows, pressure, and temperature. The systems are designed to automatically maintain the water levels in the reactor and the condenser hotwell during steady state and transient conditions.

Piping from the condenser hotwell up to but not including the outermost containment isolation valve is furnished in accordance with ANSI B31.1. Feedwater piping from the outermost primary containment isolation valve up to but not including the valve just outside the containment is designed in accordance with ASME, Section III, Class 2. Feedwater piping from the containment isolation valve to the reactor is designed in accordance with ASME, Section III, Class 1. The feedwater heaters and drain coolers are furnished in accordance with ASME Section VIII.

The condensate and feedwater systems from the condenser hotwell up to but not including the outermost primary containment isolation valve are not safety related. The feedwater system from the outermost primary containment isolation valve to the reactor is safety related. For the isolation criteria between this system and the reactor coolant boundary see Subsection 6.2.4. In-service inspection is performed in accordance with ASME Section XI for that portion of the feedwater system furnished in accordance with ASME Section III.

The condensate and feedwater systems are stress analyzed for the forces and moments that result from thermal growth. The ASME Section III feedwater pipe located inside the reactor building main steam pipe tunnel and inside the drywell is Seismic Category I.

The condensate and feedwater system is designed to permit continued operation of the plant at reduced power without reactor trip upon trip of one of the four condensate pumps, trip of one of the three reactor feed pumps, or isolation of one of the three strings of feedwater heaters.

The condensate system includes six condensate filtration vessels. The filtration vessels remove suspended (insoluble) solids, mostly iron. All six are normally in service, except during times for periodic backwash and filter element replacement. A filter vessel bypass line is provided to limit the CFS overall differential pressure to 35 psid.

The condensate and feedwater systems also include an iron injection system. The iron injection system provides the capability of regulate final feedwater iron levels to optimize feedwater chemistry.

The feedwater system also includes a zinc injection system. The zinc injection system provides the capability to regulate reactor water zinc levels to control the buildup of radiation and shutdown dose rates (Reference FSAR Section 9.5.10).

10.4.7.2 System Description

The condensate and feedwater systems are shown in Dwgs. M-105, Sh. 1, M-105, Sh. 2, M-105, Sh. 3, M-105, Sh. 4, and M-106, Sh. 1, respectively.

Four, 25 percent capacity, vertical, 10-stage, canned suction, constant speed, motor driven, centrifugal condensate pumps take a common suction from the condenser hotwell and discharge into a common header. The condensate flow is then directed through the steam jet air ejector (SJAE) condenser and the steam packing exhauster (SPE) condenser, the condensate filters, and then into the condensate demineralizer's common influent header. Condensate then proceeds through the condensate demineralizer system and discharges into a common effluent header.

The sealing water for the condensate pump glands is taken from the pump discharge or from condensate transfer pumps. It passes through a magnetic separator and cyclone separator before entering the glands. The leak off from the glands is piped to the liquid radwaste system.

A condensate recirculation system is furnished to maintain a minimum flow through each condensate pump, through the SJAE and SPE condensers and through the condensate demineralizers during low load operation. A recirculation flow of 3200 gpm per condensate pump is automatically maintained by a control valve downstream of the condensate demineralizers. Recirculated condensate is returned to the condenser.

A hotwell makeup and reject system maintains the condenser hotwell level during steady state and transient conditions. Condensate, downstream of the condensate demineralizer effluent header, is rejected to the condensate storage tank to decrease the hotwell level or condensate from the storage tank is drained into the condenser to make up the hotwell level. A small amount of reject during steady state conditions is normal. A combination of small and large control valves, with block and bypass valves, are used to control the makeup and reject flows. The small control valve controls the smaller normal flows whereas the larger control valve is used during larger transient flow. The control valves are controlled by water level in the condenser hotwell. (Refer to Subsection 10.4.1.2.)

The filtration system consists of six (6) parallel, equal size vessels. Each vessel contains replaceable filter elements. The condensate filtration system is installed directly downstream of the steam packing exhausters (SPE) condenser. The purpose of the CFS is to remove iron from the condensate. Flow exits the SPE to a supply header to the filter vessels. The supply and return headers are connected with a bypass upstream of the filters. Manual valves in each of the lines provide full flow CFS bypass capability. Additionally, a 16" line can bypass the filter vessels on high system differential pressure or manually through a remote operated valve. The 16" line has the capability to bypass the flow equivalent of two filter vessels.

The system has the capability to balance flow through each vessel regardless of how many vessels are in service or the differential pressure across an individual filter vessel. All six filter vessels are normally in service at one time except for periodic backwashing of each vessel. Backwashing is performed to limit overall CFS differential pressure to 35 psid.

Iron injection pump discharge tubing connects to the injection nozzle, which is located downstream of the condensate demineralizers. The injection pump is designed to pump soluble iron in sufficient quantities to maintain final feedwater chemistry.

Condensate from the condensate demineralizer effluent header divides and passes through three parallel strings of feedwater heaters. The feedwater passes through the tube side of an external drain cooler for heater one, then heaters one through five, respectively. Heaters one and two are located in the neck of the main condenser shells. The vents, drains and extraction steam side of the feedwater heaters are discussed in Subsection 10.4.10. Feedwater downstream of the heaters is combined into a common header from which three, 1/3 capacity, turbine driven, variable speed, barrel type, double suction, centrifugal, reactor feed pumps take suction. The reactor feed pumps discharge the feedwater into a common header for distribution through the reactor containment isolation valves and into the reactor.

Injection water for the reactor feed pump seals is taken from the effluent header of the condensate demineralizers. The inboard seals drain to number 5 feedwater heater while the outboard seals drain to the condenser. Each reactor feed pump has a recirculation line connected to the main condenser. This recirculation line is tapped off the discharge line between the reactor feed pump and its check valve, and it is used to maintain a minimum flow through the feed pump at startup and low load operation, to avoid pump vibration and high running temperatures. Proportional flow control valves in each recirculation line is regulated by a controller that senses the flow through the pumps by flow elements located in the pump discharge line and recirculation line and uses pump differential pressure as a set point reference. The control valves open proportionally as flow drops below 50 percent of the pump's best efficiency flow at that speed.

The reactor feed pumps are driven by variable speed, multistage turbines that receive steam from either the main steam cross-connection header or the crossover piping downstream of the moisture separators. During normal full power operation the turbine drivers use low pressure crossover steam. High pressure main steam is used during startup, low load, or transient conditions when crossover steam is either not available or is of insufficient pressure. The exhaust steam from each turbine is piped to the main condenser.

Before starting the reactor, the feedwater lines between the condensate demineralizer and the reactor are flushed with condensate to remove any crud present. To do this, about 50 percent of valves wide open flow is pumped through these lines by the condensate pumps, bypassing the reactor feed pumps and recirculating the flow to the condenser through the cleanup line. This ensures proper reactor water quality during startup and establishes the feedwater flow prior to admitting water into the reactor vessel.

The feedwater flow branches into two separate lines inside the reactor building. Primary containment isolation in each branch is provided by a motor operated stop check valve for the outermost containment valve and a check valve just outside the containment wall. A check valve and motor operated gate valve are located just inside the containment. (Subsection 6.2.4.)

Normally, the four condensate and three reactor feed pumps are in service together with all three strings of feedwater heaters. The system is designed so that a minimum of 74 percent of the rated feedwater flow can be maintained, without a reactor scram, with only two condensate pumps or two reactor feed pumps or two feedwater heater strings in service. Two feedwater heater strings in-service is limited by Technical Specifications.

Both the condensate pumps and reactor feed pumps are designed to provide the maximum required design flows plus adequate margin to account for 10 percent transients. Adequate margin is provided in the net positive suction head requirements to ensure noncavitating performance under all operating and runout conditions.

The condensate filters remove suspended (insoluble) solids, mostly iron base, from the condensate stream. The solids accumulate on porous filter elements until a preset vessel differential pressure is reached. The filter elements are cleaned by a backwash process.

10.4.7.3 Safety Evaluation

During operation, radioactive steam and condensate are present in the feedwater heating portion of the system, which includes the extraction steam piping, feedwater heater shells, heater drain piping, and heater vent piping. Shielding and controlled access are provided as necessary (see Section 12.1 for details). The condensate and feedwater system is designed to minimize leakage, with welded construction used where practicable. Relief valve discharges and operating vents are handled through closed systems.

If it is necessary to remove a component such as a feedwater heater, condensate or feedwater pump, or any control valve from service, continued operation of the system is possible by use of the multistream arrangement and the provisions for removing from service and bypassing equipment and sections of the system.

An abnormal operational transient analysis of the loss of feedwater heater string is included in Chapter 15.

The probability of releasing radioactivity to the environment due to a pipe break outside the primary containment is minimized by the containment isolation valves. The primary containment prevents the release of radioactivity to the environment should a feedwater line break occur inside the primary containment.

The nonseismic portions of the condensate and feedwater system, i.e., those portions upstream of the outermost containment isolation valves, are not essential for safe shutdown of the plant. If a pipe break occurs in the nonseismic piping, the reactor level will fall and on low-low level the high pressure coolant injection pumps will be started automatically and a reactor trip will be initiated. The location of equipment in the turbine building in the vicinity of the feedwater piping is such that no safety-related component could be flooded by a rupture in the feedwater lines.

The CFS adds approximately up to 35 psid to the overall condensate system resistance. This additional system pressure loss results in a reduction of Reactor Feed Pump (RFP) suction pressure. The additional differential pressure imposed by CFS reduces the margin available during anticipated balance of plant transients that affect RFP suction pressure such that one or more RFP trips may occur prior to plant/operator response to stabilize the affected systems. The RFP trip on low suction pressure has been modified to stagger the pump trip. The time delays between RFP suction pressure trips have been increased for Extended Power Uprate. This action prevents tripping all three RFPs simultaneously and assures improved capability to survive a sudden reduction in suction pressure.

The condensate filtration system valves' failure positions are selected to minimize potential reduction of feedwater flow due to a component or system failure. Failure positions are:

- Vessel inlet/outlet valves – as-is.
- Vessel flow control valves – open
- Vessel bypass valve – as-is on loss of air (open on loss of signal)
- Backwash process valves – closed

Failure of the condensate filtration system is bounded by the analysis in Subsection 15.2.7.

10.4.7.4 Tests and Inspections

That portion of the feedwater system designed to ASME Section III Class 1 or 2 was inspected and tested in accordance with Articles 5000 and 6000 of the ASME III Code. That portion of the condensate and feedwater system designed to ANSI B31.1 was inspected and tested in accordance with Paragraphs 136 and 137 of ANSI B31.1.

Performance tests were made on all condensate and reactor feed pumps in accordance with ASME Power Test Codes for Centrifugal Pumps, PTC 8.2.

The casings of the condensate and reactor feed pumps were hydrostatically tested to 1.5 times their design pressures. The condensate filter vessels and the shell and tube side of all feedwater heaters and drain coolers were hydrostatically tested to 1.5 times their design pressure in accordance with ASME Section VIII.

Before initial operation, the completed condensate and feedwater system received a field hydrostatic test and inspection in accordance with the applicable code. Periodic tests and inspections of the system are performed in conjunction with scheduled maintenance outages per plant procedures.

The system was preoperationally tested in accordance with the requirements of Chapter 14.

10.4.7.5 Controls and Instrumentation

Controls are provided to maintain condenser hotwell level so that on high level the condensate pump discharges the surplus condensate to the condensate storage tank while on low level makeup from the storage tank is admitted to the system.

Each of the four higher pressure feedwater heaters are provided with two level transmitters to maintain the correct level of condensate in the respective heater shell. One transmitter modulates the valve which controls the normal drain flow from the respective heater to the next lower pressure heaters. The other transmitter modulates the high level dump valve and this operates only when the water level in the heater shell rises above the high level setting of the transmitter regulating the normal drain flow. The dump valve discharges directly into the main condenser. On loss of control air the normal drain valve fails closed while the dump valve fails open. This prevents the flooding of the next lower pressure heater.

The condensate filtration system is provided with redundant PLCs for local control of system components and display of filter flow, system flow, filter differential pressure, and system differential pressure. The PLCs are configured with an “active” and “standby” unit, both receiving the same inputs to permit a smooth and quick transition to the standby unit if required. The condensate filtration system PLC provides inputs to the Plant Integrated Computer System (PICSY) via the WCDAS LAM for remote indication of system performance.

The iron injection system is designed for local control only. The iron injection pump flow rate is manually adjusted to achieve desired iron injection rates.

In addition to two level transmitters, each of the three higher pressure feedwater heaters has a high-high level switch and each of the two lower pressure heaters has two high-high level switches. Operation of the high-high level switches in the top three heaters closes the isolation valves in the respective extraction steamlines to prevent water induction into the turbine. Operation of one of the high-high level switches on the two lower pressure heaters closes the drain valve from the preceding heater. If after this action the water level continues to rise, the second high-high level switch will isolate the entire heater string on the feedwater side.

The reactor is filled initially by the condensate pumps, through the start-up control valves which bypass the reactor feed pumps and allows the condensate pumps to discharge directly into the reactor. During this period the level in the reactor is maintained by the smaller start-up valve which is modulated manually from the control room.

When reactor pressure approaches condensate pump pressure a reactor feed pump is started and feedwater is supplied to the reactor through the large start-up control valve which is regulated by single element control (reactor level). This mode of control will operate until the reactor is up to approximately 20 percent of power level. At this point the RFP discharge valves are opened, the large start-up control valve closed, and the feedwater placed on 3 element control which regulates the feedwater flow by adjusting the speed of the reactor feed pumps. The feedwater flow elements also provide inputs to the Hydrogen Water Chemistry System (Reference Section 9.5.9) to adjust hydrogen injection rates with plant power. Hydrogen is normally injected at the suction of each of the reactor feed pumps, when reactor power is greater than approximately 30%.

Monitoring systems including pressure indicators, flow and temperature indicators, and alarms for abnormal conditions are provided in the control room to ensure the proper operation of system components. "Electrochemical corrosion potential (ECP) monitoring of the reactor water to determine hydrogen injection effectiveness is provided using the Water Chemistry Data Acquisition System."

The reactor recirculation pumps will automatically run back upon anticipated loss of feedwater if any one of the following occurs:

a) Trip of any condensate pump to approximately 48% rated speed.

b) Isolation of one string of feedwater heaters due to high-high water level in feedwater heaters one or two (Subsection 10.4.10) plus low reactor water level 4.

c) Low flow to the reactor at any reactor feed pump discharge.

d) Trip of any circulating water pump.

Flow elements are provided at major points along the condensate and feedwater system, in the feedwater heater drains, and in the makeup and reject lines. Abnormal flows will indicate pipe breaks or tube leaks.

An ultrasonic Leading Edge Flow Meter (LEFM) is provided on the discharge of each feedwater pump to provide an accurate measurement of feedwater flow and temperature into the Plant Integrated Computer System and subsequently to the Powerplex computer for use in the calculation of core thermal power.

The feedwater control system is described in Subsection 7.7.1.4.

10.4.8 STEAM GENERATOR BLOWDOWN SYSTEM (PWR)

Not applicable to BWR.

10.4.9 AUXILIARY FEEDWATER SYSTEM (PWR)

Not applicable to BWR

10.4.10 EXTRACTION STEAM AND FEEDWATER HEATER DRAIN AND VENT SYSTEM

10.4.10.1 Design Basis

The Extraction Steam and Feedwater Heater Drain and Vent System has no safety-related function.

a) Extraction Steam System

The extraction steam system is designed to supply steam from intermediate stages of the main turbine to closed feedwater heaters to heat the feedwater to 391° F at reactor rated flow. The system is designed and meets the requirements of the ASME standard, "Recommended Practices for the Prevention of Water Damage to Steam Turbines Used for Electric Power Generation, Part 2 Nuclear Fueled Plants", to prevent water induction into the turbine.

b) Feedwater Heater Drain and Vent System

The feedwater heater and drain cooler vents and drains system is designed to accomplish the following objectives during steady and transient loads from startup to full load to shutdown:

1) Remove non-condensable gases continuously from the condenser drains to assure good heat transfer over the tube surfaces.

2) Drains cascade continuously from each heater to the next lower pressure heater and then to the main condenser while maintaining the desired water level in all heaters.

3) In the event of excessively high level in any heater, dump the drains from that heater directly to the condenser.

4) Prevent water backing up into the turbine through the extraction lines to heaters 2A, 2B and 2C.

These systems are designed and installed in accordance with the requirements of applicable codes, and standards shown in Table 3.2-1.

The design pressures and temperatures of the feedwater heaters are shown in Table 10.4-6.

10.4.10.2 System Description

For Unit 1, the extraction steam system is shown on Dwgs. M-102, Sh. 1, M-102, Sh. 2, and M-102, Sh. 3. For Unit 2, the extraction steam system is shown on Dwgs M-2102, Sh. 1, M-2102, Sh. 2, and M-2102, Sh. 3. The feedwater heater drain and vent system is shown on Dwgs. M-103, Sh. 1 and M-104, Sh. 1. These systems include:

Bleeder trip valves
Extraction steamline motor operated isolating valves
Extraction steamline drain valves
Associated piping, valves, controls, and instrumentation

Extraction Steam System

Under normal operation, steam is extracted from the turbine to the shell side of the feedwater heaters to heat feedwater flowing on the tube side. Five stages of heating are provided. The pressure, temperature, and flow of the extraction steam vary in accordance with the load on the turbine.

Bleeder trip valves (BTV), extraction steam isolation valves and associated drain valves are provided in the extraction lines as required by the turbine manufacturer to prevent turbine overspeed due to flashing steam flowing back into the turbine in the event of a turbine trip, and also to prevent water induction into the turbine in the event of heater tube failure.

The extraction lines to feedwater heaters 3A, B & C, 4A, B & C, and 5A, B & C each contain a bleeder trip valve and in addition each has a motor-operated isolating valve located downstream of the BTVs.

No non-return valves are installed in the extraction lines to heaters 1A, B & C and 2A, B & C since the use of antiflash baffles in these heaters eliminates the need for them.

Each of the extraction lines to heaters 3A, B & C, 4A, B & C, and 5A, B & C is provided with two drain lines, one on the turbine side of the respective bleeder trip valve and the other between the bleeder trip valve and the respective isolating valve.

The drain lines on the turbine side of the bleeder trip valves in the extraction lines are interlocked with their respective bleeder trip valves and isolating valves such that when either of these valves close the drain valves open.

The valves in the drain lines between the bleeder trip valves and the isolating valves will open on either turbine trip or high-high level in the respective heater. The high-high level signal and turbine trip will also close the respective isolating valve. Once closed the isolating valve can only be opened by the operator either when the water level has returned to normal, or when during startup the high-high level interlock is bypassed to permit valve operation thus promoting heater drainage.

The interlocks can be overridden by hand switches so that at start up the drains can be operated.

The drains from Heaters 1A, B & C flow continuously through unvalved drain lines to their respective drain cooler. From there the drains discharge into the main condenser, entering at a point below the elevation of the heaters, thus preventing flooding of the heaters after a main turbine trip or as a result of large feedwater heater tube leakage.

The bleeder trip valves are provided with side-pilot air cylinders that, on loss of air pressure following either high feedwater heater level or main turbine trip, provide a closing impulse to the bleeder trip valves. This closing impulse is primarily to insure that the bleeder trip valve disc is not "hung-up" from long periods of operation in the open position. A test switch is provided for each bleeder trip valve for checking of the valve's operability with the positive closing cylinder.

Moisture Separator Drains

Drains from each moisture separator are collected in an integral drain tank and then discharged to Feedwater Heaters 4A, B, C, or to the condenser as dictated by level controllers on the drain tank.

Feedwater Heater Vents and Drains System

During startup, the large volume of air in the heater shell is vented into the main condenser through a remote manual operated valve in the startup vent header from each heater. The nozzle connection in the operating vent line on each heater is sized to choke the flow in the line such that an orifice or throttling valve is not necessary.

The heater drain normal-level and high-level (dump) control valves for each heater are each controlled by an individual level transmitter and associated controller. Normally, only the heater normal-level drain valve is modulated to maintain heater shell level.

The high-level (dump) control valve opens only when the water level rises above the high level setting of the normal level controller and passes the drains directly to the condenser.

Loss of control air results in loss of control over the heater water level. To prevent sudden flooding of the next lower pressure heater on control air failure, the normal-level control valve is designed to fail closed on loss of air and the dump valve to fail open on loss of air. The heater drain lines from feedwater heaters 1A, B & C and associated external drain coolers to the condenser shells serve as loop seals; therefore drain control valves are not required. This arrangement precludes water from backing-up through heaters 1A, B and C extraction lines into the main turbine should large feedwater tube leaks occur. Flow from each drain cooler is measured by a venturi flowmeter and the signal is fed to the computer to detect tube leakage.

Shell relief valves are provided to prevent shell over-pressure in the event of tube leakage and closing of the bleeder trip valves in the extraction lines.

Feedwater heaters 1A, 1B, 1C, 2A, 2B, and 2C each have a high-high level switch which when operated will close the respective drain valve from the preceding heater and annunciate an alarm. If the level in the respective heater continues to rise after the alarm has been annunciated a separate level switch will operate to isolate the entire heater string on the feedwater side.

10.4.10.3 Safety Evaluation

During operation, radioactive steam is present in the extraction steam piping and feedwater heater shells. Shielding and controlled access are provided as necessary (see Section 12.3 for details). Both systems are designed to minimize leakage, with welded construction used where practicable.

10.4.10.4 Tests and Inspections

Each feedwater heater and drain cooler received a shop hydrostatic test in accordance with ASME Section VIII, Division 1 requirements. All tube joints of feedwater heaters were shop leak tested. Prior to initial operation, the condensate and feedwater system received a field hydrostatic test and inspection to verify the system integrity. Periodic tests and inspections of the system are performed in conjunction with scheduled maintenance outages.

The system was preoperationally tested in accordance with the requirements of Chapter 14.

10.4.10.5 Controls and Instrumentation

There are several locations at which extraction steam pressure and temperature is measured. Controls are provided to actuate automatically the extraction steam check valves, shut-off valves, and drain valves as described in Subsection 10.4.10.2.

Instrumentation and controls are provided for regulating the heater drain flow rate to maintain the proper condensate level in each feedwater heater shell or heater drain tank. High-level alarms and automatic dump action on high level and automatic isolation of a heater on high-high level are also provided.

Alarms for FW heater and MS drain tank level are provided in the control room to alert the operator to take any necessary action.

10.4.11 AUXILIARY STEAM SYSTEM

10.4.11.1 Design Bases

The Auxiliary Steam System has no safety-related function; is non-Seismic, and is designed to operate independently of the Nuclear Steam Supply System. The system provides clean steam to various plant processes.

The Auxiliary Steam Boilers are designed in accordance with Section 1, ASME Boiler and Pressure Vessel Code, and in compliance with applicable state and local regulations.

The system is designed to provide the operational flexibility necessary to accommodate the varying steam demands during all modes of operation.

10.4.11.2 System Description

The Auxiliary Steam System consists of two electrode steam boilers. Each boiler is supplied with an integral recirculation pump, a seal cooling skid, a boiler feed pump, a boiler blowdown separator, a trisodium phosphate tank and a chemical feed pump. These boilers have one common sodium sulfite tank with an injection pump and one common deaerator with a feedwater heater and a recycle pump, and all associated piping, valves, controls and instrumentation. All major components of the Auxiliary Steam System are in the Unit 1 turbine building. The boiler controls are designed for automatic operation. The piping system is designed for single or dual boiler operation.

A pressure reducing station maintains system pressure. Final pressure reduction is accomplished, as required, by individual valves adjacent to the equipment served.

The Auxiliary Steam System provides an automatic backup for the steam seal system. The boilers can be cycled ramped on or shut off, by a header pressure switch which will maintain the boilers at or near operating pressure and temperature during no load periods. In case of sudden demand for steam the ramped "on" cycle is overridden by a supplementary header pressure switch to permit full output in less than 20 seconds. Since the auxiliary boiler load is minimal during normal plant operations, the second boiler may be maintained in hot standby by a 45 KW standby heater bank.

Auxiliary steam is also available for the radwaste evaporators, off-gas recombiner during startup and radwaste building decontamination shop.

During initial plant startup, auxiliary steam was used to test the HPCI, RCIC, and RFP turbines. Auxiliary steam is also available during startup from refueling to perform retest on HPCI, RCIC, and RFP turbines and to operate the steam jet air ejectors, and for condenser hotwell deaeration.

The condensate from any potentially contaminated source is routed to the LP condenser. Condensate from most steamline traps and some auxiliary steam loads is returned to the auxiliary boiler deaerator.

Makeup for the auxiliary steam boilers is taken from the demineralized water system through the deaerator.

The boiler water conductivity controller regulates conductivity by either activating the chemical feed pump on low conductivity or causing the boiler to blow down to the radwaste system on high conductivity.

The connections between the Auxiliary Steam System and Seismic Category I systems such as HPCI, RCIC and RFP turbines, were used for preoperational testing and continue to be used during every startup subsequent to refueling for retesting. The connections are made through removable pipe spools, installation and removal of which is controlled by a written procedure. Before startup, the pipe spools are removed and the Auxiliary Steam System is disconnected from any Seismic Category I systems. The connections between the Auxiliary Steam System and non-Seismic portions of the Main Steam System are protected by normally closed valves.

10.4.11.3 Safety Evaluation

The Auxiliary Steam System is designed such that a failure of the system will not compromise any safety-related system or prevent a safe reactor shutdown. The system is protected against high pressure, low and high boiler water level, overcurrent, and other malfunctions.

10.4.11.4 Test and Inspections

The Auxiliary Steam System is proven operable by its use during startup and normal plant operations. The system was preoperationally tested in accordance with the requirements of Chapter 14.

10.4.11.5 Instrumentation Application

Each boiler is equipped with temperature, pressure, and level indicators. Flow in each boiler outlet and pressure in the main header is indicated in the control room and on the boiler local panel.

The boiler feed pumps are operated by the boiler level controllers.

Abnormal water level, conductivity or pressure is alarmed on the local panels and as a group alarm in the control room.

Table Rev. 36

TABLE 10.4-1

CONDENSER DESIGN PARAMETERS

	L. P. Shell	I. P. Shell	H. P. Shell
No. of Passes	1	1	1
Pressure, Turbine exhaust with HqA	2.99	3.56	4.43
Circulating Water Flow, GPM Inlet Temp	448,000 87.0	448,000	448,000
Cleanliness factor, %	95%	95%	95%
Surface area, sq. ft.	219,700	293,300	367,000
Condenser Duty 10^9 Btu/hr.	2.67	2.66	2.56
Tube velocity, ft/sec.	7.34	7.33	7.32
Effective tube length, ft.	30'-0"	40'-0"	50'-0"
Tube O.D. Tube Material ASTM A-249, Type 304 Stainless Steel	1.0"	1.0"	1.0"
Tube BWG Impingement Zone Main Condensing & Air Cooling Zones	20 BWG 22 BWG	20 BWG 22 BWG	20 BWG 22 BWG
Maximum free 0 in condensate leaving hotwell, Guaranteed cc/liter 10% to 100% load range	--	--	0.005
At all other loads, max cc/liter	--	--	0.03

Table 10.4-2
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Table 10.4-3

CIRCULATING WATER QUALITY DESIGN PARAMETERS
USED FOR THE CONDENSATE CLEANUP SYSTEM

Constituent	Concentration
Hardness (ppm as $CaCo_3$)	630.0
Total Dissolved Solids (ppm)	1440.0
Suspended Matter (ppm)	Varies 10 to 500
Ammonia (ppm as N)	0.44
Total Sulfides (ppm as S)	0.01
Silica (ppm as SiO_2)	7.3
Iron (ppm as Fe)	0.44
Manganese (ppm as Mn)	0.69
Calcium (ppm as Ca)	173.0
Magnesium (ppm as Mg)	48.7
Solium & Potassium (ppm as Na)	12.4 to 24.4
Bicarbonate (ppm as HCO_3)	73.0
Sulfate (ppm as SO_4)	503.0
Chloride (ppm as Cl)	47.0
Nitrate (ppm as NO_3)	3.0
Free Chlorine (intermittent ppm)	0.2 to 0.5
pH Value (average)	6.8 to 7.5

TABLE 10.4-4

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TABLE 10.4-5

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TABLE 10.4-6

DESIGN CONDITIONS FOR FEEDWATER HEATERS

	Heaters 1 & 2	Heater 3	Heater 4	Heater 5	Drain Cooler
Design pressure, shell side	50 psig and full vacuum	75 psig and full vacuum	230 psig and full vacuum	275 psig and full vacuum (See Note 1)	50 psig and full vacuum
Design Temperature shell side, °F	300	320	395	410	300
Design pressure, tube side, psig	740	740	740	740	740
Design Temperature, tube side, °F	300	320	395	410	300
Feedwater maximum velocity @ rated flow and 60°F, ft/sec	9.38 (#1) 9.39 (#2)	5.64 (01) 6.19 (02)	7.91	7.75	8

Note 1: Unit 1 FWH 5A rated at 270 psig. Unit 1 FWH 5B and 5C rated at 260 psig. Unit 2 FWH 5A,B,C rated at 275 psig.

Heater	Terminal Temperature Difference, °F	Drain Subcooler Approach, °F
1	9.7	37.8
2	9.4	18.5
3	5.0 (U1) 5.6 (U2)	10.0 (U1) 9.7 (U2)
4	8.0	13.4
5	7.0	11.9

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RENUMBERED TO 10.4-2-1

FSAR REV. 53, 4/99

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 AND 2
FINAL SAFETY ANALYSIS REPORT

Figure renumbered from 10.4-2 to 10.4-2-1

FSAR FIGURE 10.4-2

PP&L DRAWING E106221, sh 1

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RENUMBERED TO 10.4-2-2

FSAR REV. 53, 4/99

SUSQUEHANNA STEAM ELECTRIC STATION UNITS 1 AND 2 FINAL SAFETY ANALYSIS REPORT
Figure renumbered from 10.4-3 to 10.4-2-2
FSAR FIGURE 10.4-3

PP&L DRAWING E106221, sh 2

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FSAR REV. 51, 02/97

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 AND 2
FINAL SAFETY ANALYSIS REPORT

REFER TO FIGURES:
10.4-4-1, 10.4-4-2 and 10.4-4-3

FSAR FIGURE 10.4-4

PP&L DRAWING n/a

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RENUMBERED TO 10.4-5-1

FSAR REV. 53, 4/99

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 AND 2
FINAL SAFETY ANALYSIS REPORT

Figure renumbered from 10.4-5 to 10.4-5-1

FSAR FIGURE 10.4-5

PP&L DRAWING E106211, sh 1

THIS FIGURE HAS BEEN

REPLACED BY DWG.

M-103, Sh. 1

FSAR REV. 58

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 AND 2
FINAL SAFETY ANALYSIS REPORT

Figure 10.4-7 replaced by dwg.
M-103, Sh. 1

FSAR FIGURE 10.4-7, Rev. 54

PPL DRAWING E106208, Sh. 1

THIS FIGURE HAS BEEN

REPLACED BY DWG.

M-104, Sh. 1

FSAR REV. 58

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 AND 2
FINAL SAFETY ANALYSIS REPORT

Figure 10.4-8 replaced by dwg.
M-104, Sh. 1

FSAR FIGURE 10.4-8, Rev. 54

PPL DRAWING E106209, Sh. 1

THIS FIGURE HAS BEEN

RENUMBERED TO 10.4-9-1

FSAR REV. 53, 4/99

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Figure renumbered from 10.4-9 to 10.4-9-1

FSAR FIGURE 10.4-9

PP&L DRAWING E106212, sh 1

THIS FIGURE HAS BEEN

REPLACED BY DWG.

M-101, Sh. 1

FSAR REV. 58

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**Figure 10.4-1-1 replaced by dwg.
M-101, Sh. 1**

FSAR FIGURE 10.4-1-1, Rev. 54

PPL DRAWING E106206, Sh. 1

THIS FIGURE HAS BEEN

REPLACED BY DWG.

M-101, Sh. 2

FSAR REV. 58

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Figure 10.4-1-2 replaced by dwg. M-101, Sh. 2
FSAR FIGURE 10.4-1-2, Rev. 54

PPL DRAWING E106206, Sh. 2

THIS FIGURE HAS BEEN

REPLACED BY DWG.

M-101, Sh. 3

FSAR REV. 58

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Figure 10.4-1-3 replaced by dwg.
M-101, Sh. 3

FSAR FIGURE 10.4-1-3, Rev. 54

PPL DRAWING E106206, Sh. 3

THIS FIGURE HAS BEEN

REPLACED BY DWG.

M-116, Sh. 1

FSAR REV. 58

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Figure 10.4-2-1 replaced by dwg.
M-116, Sh. 1

FSAR FIGURE 10.4-2-1, Rev. 55

PPL DRAWING E106221, Sh. 1

THIS FIGURE HAS BEEN

REPLACED BY DWG.

M-116, Sh. 2

FSAR REV. 58

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Figure 10.4-2-2 replaced by dwg. M-116, Sh. 2 FSAR FIGURE 10.4-2-2, Rev. 55

PPL DRAWING E106221, Sh. 2

THIS FIGURE HAS BEEN

REPLACED BY DWG.

M-116, Sh. 3

FSAR REV. 58

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Figure 10.4-2-3 replaced by dwg. M-116, Sh. 3

FSAR FIGURE 10.4-2-3, Rev. 55

PPL DRAWING E106221, Sh. 3

THIS FIGURE HAS BEEN

REPLACED BY DWG.

M-105, Sh. 1

FSAR REV. 58

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Figure 10.4-4-1 replaced by dwg.
M-105, Sh. 1

FSAR FIGURE 10.4-4-1, Rev. 55

PPL DRAWING E106210, Sh. 1

THIS FIGURE HAS BEEN

REPLACED BY DWG.

M-105, Sh. 2

FSAR REV. 58

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Figure 10.4-4-2 replaced by dwg. M-105, Sh. 2
FSAR FIGURE 10.4-4-2, Rev. 54

PPL DRAWING E106210, Sh. 2

THIS FIGURE HAS BEEN

REPLACED BY DWG.

M-105, Sh. 3

FSAR REV. 58

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Figure 10.4-4-3 replaced by dwg. M-105, Sh. 3 **FSAR FIGURE 10.4-4-3, Rev. 54**

PPL DRAWING E106210, Sh. 3

THIS FIGURE HAS BEEN

REPLACED BY DWG.

M-105, Sh. 4

FSAR REV. 58

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Figure 10.4-4-4 replaced by dwg. M-105, Sh. 4
FSAR FIGURE 10.4-4-4, Rev. 1

PPL DRAWING E106210, Sh. 4

THIS FIGURE HAS BEEN

REPLACED BY DWG.

M-106, Sh. 1

FSAR REV. 58

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Figure 10.4-5-1 replaced by dwg. M-106, Sh. 1
FSAR FIGURE 10.4-5-1, Rev. 55

PPL DRAWING E106211, Sh. 1

THIS FIGURE HAS BEEN

REPLACED BY DWG.

M-106, Sh. 2

FSAR REV. 58

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Figure 10.4-5-2 replaced by dwg.
M-106, Sh. 2

FSAR FIGURE 10.4-5-2, Rev. 56

PPL DRAWING E106211, Sh. 2

THIS FIGURE HAS BEEN

REPLACED BY DWG.

M-106, Sh. 3

FSAR REV. 58

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Figure 10.4-5-3 replaced by dwg.
M-106, Sh. 3

FSAR FIGURE 10.4-5-3, Rev. 55

PPL DRAWING E106211, Sh. 3

THIS FIGURE HAS BEEN

REPLACED BY DWG.

M-106, Sh. 4

FSAR REV. 58

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Figure 10.4-5-4 replaced by dwg.
M-106, Sh. 4

FSAR FIGURE 10.4-5-4, Rev. 55

PPL DRAWING E106211, Sh. 4

THIS FIGURE HAS BEEN

REPLACED BY DWG.

M-106, Sh. 5

FSAR REV. 58

SUSQUEHANNA STEAM ELECTRIC STATION **UNITS 1 AND 2** **FINAL SAFETY ANALYSIS REPORT**
Figure 10.4-5-5 replaced by dwg. M-106, Sh. 5 **FSAR FIGURE 10.4-5-5, Rev. 55**

PPL DRAWING E106211, Sh. 5

THIS FIGURE HAS BEEN

REPLACED BY DWG.

M-102, Sh. 1

FSAR REV. 58

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Figure 10.4-6-1 replaced by dwg.
M-102, Sh. 1

FSAR FIGURE 10.4-6-1, Rev. 55

PPL DRAWING E106207, Sh. 1

THIS FIGURE HAS BEEN

REPLACED BY DWG.

M-102, Sh. 2

FSAR REV. 58

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Figure 10.4-6-2 replaced by dwg.
M-102, Sh. 2

FSAR FIGURE 10.4-6-2, Rev. 55

PPL DRAWING E106207, Sh. 2

THIS FIGURE HAS BEEN

REPLACED BY DWG.

M-102, Sh. 3

FSAR REV. 58

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Figure 10.4-6-3 replaced by dwg. **M-102, Sh. 3** **FSAR FIGURE 10.4-6-3, Rev. 55**

PPL DRAWING E106207, Sh. 3

THIS FIGURE HAS BEEN

REPLACED BY DWG.

M-107, Sh. 1

FSAR REV. 58

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**Figure 10.4-9-1 replaced by dwg.
M-107, Sh. 1**

FSAR FIGURE 10.4-9-1, Rev. 54

PPL DRAWING E106212, Sh. 1

THIS FIGURE HAS BEEN

REPLACED BY DWG.

M-107, Sh. 2

FSAR REV. 55

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Figure 10.4-9-2 replaced by dwg.
M-107, Sh. 2

FSAR FIGURE 10.4-9-2, Rev. 54

PPL DRAWING E106212, Sh. 2

THIS FIGURE HAS BEEN

REPLACED BY DWG.

M-107, Sh. 3

FSAR REV. 58

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Figure 10.4-9-3 replaced by dwg. M-107, Sh. 3
FSAR FIGURE 10.4-9-3, Rev. 54

PPL DRAWING E106212, Sh. 3

THIS FIGURE HAS BEEN

REPLACED BY DWG.

M-107, Sh. 4

FSAR REV. 58

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Figure 10.4-9-4 replaced by dwg. M-107, Sh. 4 FSAR FIGURE 10.4-9-4, Rev. 54

PPL DRAWING E106212, Sh. 4

THIS FIGURE HAS BEEN
REPLACED BY DRAWING M-2101, SH. 1

FSAR REV. 59

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Figure replaced by M-2101, Sh. 1

FIGURE 10.4-1-1A, Rev. 0

PPL DWG. E105901, Sh. 1

THIS FIGURE HAS BEEN
REPLACED BY DRAWING M-2101, SH. 2

FSAR REV. 59

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Figure replaced by M-2101, Sh. 2

FIGURE 10.4-1-2A, Rev. 0

PPL DWG. E105901, Sh. 2

THIS FIGURE HAS BEEN
REPLACED BY DRAWING M-2101, SH. 3

FSAR REV. 59

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Figure replaced by M-2101, Sh. 3

FIGURE 10.4-1-3A, Rev. 0

PPL DWG. E105901, Sh. 3

THIS FIGURE HAS BEEN

REPLACED BY DWG.

M-2106, Sh. 2

FSAR REV. 58

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Figure 10.4-5-2A replaced by dwg.
M-2106, Sh. 2

FSAR FIGURE 10.4-5-2A, Rev. 1

PPL DRAWING E162777, Sh. 2

THIS FIGURE HAS BEEN

REPLACED BY DWG.

M-2106, Sh. 3

FSAR REV. 58

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Figure 10.4-5-3A replaced by dwg.
M-2106, Sh. 3

FSAR FIGURE 10.4-5-3A, Rev. 1

PPL DRAWING E162777, Sh. 3

THIS FIGURE HAS BEEN

REPLACED BY DWG.

M-2106, Sh. 4

FSAR REV. 58

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Figure 10.4-5-4A replaced by dwg. **M-2106, Sh. 4** **FSAR FIGURE 10.4-5-4A, Rev. 1**

PPL DRAWING E162777, Sh. 4

THIS FIGURE HAS BEEN
REPLACED BY DRAWING M-2102, SH. 1

FSAR REV. 59

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Figure replaced by M-2102, Sh. 1

FIGURE 10.4-6-1A, Rev. 0

PPL DWG. E162635, Sh. 1

THIS FIGURE HAS BEEN
REPLACED BY DRAWING M-2102, SH. 2

FSAR REV. 59

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Figure replaced by M-2102, Sh. 2

FIGURE 10.4-6-2A, Rev. 0

PPL DWG. E162635, Sh. 2

THIS FIGURE HAS BEEN
REPLACED BY DRAWING M-2102, SH. 3

FSAR REV. 59

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Figure replaced by M-2102, Sh. 3

FIGURE 10.4-6-3A, Rev. 0

PPL DWG. E162635, Sh. 3